The Economics and Governance of Multipurpose Hydropower Reservoirs

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Doctor of Philosophy
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Declaration

I declare that the research presented in this thesis represents original work that I carried out during my PhD candidature at the Australian National University. I confirm that no material included in this thesis has been previously submitted by me for the purpose of obtaining a degree from any university or tertiary educational institution. This thesis is my independent work, except for Chapter 3 which was previously published as:

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The Chair of my PhD supervisory panel is the second author on the above paper. He has agreed to the following description of the roles that myself and my co-authors played in (i) the authorship of the paper, and (ii) the design, coordination, and implementation of the underlying project:

Wyrwoll prepared the first, second, and third draft of the paper, as well as the final version accepted by the journal that incorporated referees' comments. Grafton, Daniell, Chu, and Do provided comments and revisions on the first draft. Ringler, Grafton, Daniell, Chu, Lien, Khoi, and Tuan provided comments and revisions on the second draft. Grafton provided comments on referees' responses and the final version of the paper accepted by the journal. Wyrwoll, Grafton, and Daniell designed the project. Wyrwoll, Lien, and Grafton designed the participatory workshop which was facilitated by Lien. Wyrwoll coordinated and revised analysis of workshop participants' policy options by Chu, Daniell, Grafton, Ringler, and Wyrwoll. Lien and Khoi coordinated and conducted field surveys of farmers designed by Wyrwoll, Lien, and Khoi. Lien, Khoi, and Tuan coordinated access to the project site and workshop participants.

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Abstract

Hydropower reservoirs can provide a range of energy and water services. Proponents of multipurpose reservoirs as a climate change and water security 'solution' often neglect an important detail: the technical capacity for infrastructure to provide water services and social benefits is a necessary but not sufficient condition for their actual provision. Multipurpose operations constrain electricity generation and hydropower companies' revenues. The opportunity costs of providing non-energy services are changing under the global transition to renewable energy systems. The value of water services shifts as water demand and supply change under short-term shocks, such as extreme weather events, and long-term trends, such as climate change and population growth. Under dynamic risks and trade-offs, profit-motivated hydropower companies do not have the discretion nor information to efficiently and equitably provide water services. The potential social benefits of multipurpose hydropower operations are not automatic; they need to be secured through flexible regulation and economic incentives. This thesis considers the governance of multipurpose hydropower reservoirs and the dynamic trade-offs between the profits of hydropower companies and the welfare of water users. First, I review existing hydropower governance instruments to propose three reforms: (1) period relicensing of reservoir operations, (2) pricing water services to reflect the value of foregone hydroelectricity generation, and (3) climate/green performance bonds with a conditional interest rate. Second, I consider how economic and institutional analyses could be incorporated into the governance of water systems under complex risks. Insights are drawn from a participatory risk assessment process in Vietnam where local government officials are piloting irrigation water pricing reforms. Third, I use hydro-economic modelling of a multipurpose reservoir in Tasmania, Australia to examine the conditions under which irrigation water pricing could be an appropriate reform in other locations. Finally, I consider a major practical barrier to pricing water services from hydropower reservoirs: the transmission of price spikes in electricity markets to water prices. I estimate the cost of price stability controls by modelling an alternative water tariff which incorporates the intertemporal opportunity costs of irrigation water extractions. I conclude by outlining future research on regulating hydropower reservoirs to support the resilience of social-ecological systems to water insecurity.

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Chapter 1

Introduction

Growing awareness of the negative environmental and social impacts from large dams led to a global slowdown in new hydropower projects between 1998 and 2005 (WEC 2015a). This stagnation was temporary: the present-day construction boom is projected to increase global hydropower generation capacity by 53% between 2016 and 2040 (IEA 2018). Overall, an estimated 847 large hydropower projects (with generation capacity > 100MW) are either planned or under construction (Zarfl et al. 2015). Climate change and energy policy are driving this resurgence: key decision-makers perceive the flexible generation and storage of renewable energy by hydropower projects as central to: (i) improving energy access and supporting economic development in poor and emerging economies, and (ii) decarbonizing the world's energy systems and economies (DOE 2016; IEA 2012; Rex et al. 2014). The shifting perceptions of large-scale hydropower were illustrated by a senior World Bank official:

> "Large hydro is a very big part of the solution for Africa and South Asia and Southeast Asia… I fundamentally believe we have to be involved," said Rachel Kyte, the bank's vice president for sustainable development and an influential voice among (former World Bank president Jim Yong) Kim's top staff members. The earlier move out of hydro "was the wrong message…. That was then. This is now. We are back."

(Schneider 2013)

Central to the (rediscovered) legitimacy of hydropower are the potential co-benefits for water governance (e.g. Branche 2015; IFC/TNC 2017; Opperman et al. 2017). Reservoirs often serve multiple purposes and hydropower reservoirs can provide a range of valuable water-based services beyond electricity generation (Bonnet et al. 2015; IEA Hydropower Agreement 2017). Hence, new and existing hydropower reservoirs could support the resilience of agricultural, urban, and industrial water systems to risks. For example, maintaining water security under severe droughts or protecting downstream populations from flooding. However, the realisation of these anticipated benefits will depend on the reservoir operation decisions that hydropower companies make within the boundaries provided by regulation.

Water services provision constrains the decision space and, frequently, the revenues of profit-motivated hydropower companies (Zeng et al. 2017). Water licenses, reservoir and flow constraints, and other conventional approaches to regulating water services are typically static. Yet, the trade-offs between hydropower companies' profits and water users' welfare are dynamic. The values of water and energy services shift under variable electricity prices, energy policy reforms, and changing weather, climate, and water demand. Further, the benefits of water and energy services are not just private: energy access, flood control, and urban water security generate a range of positive externalities. For multipurpose hydropower reservoirs, a balance has to be struck between energy and water services provision, but it is not obvious what that balance should be at any one point in time nor, from a regulatory perspective, how to achieve it. Should operating constraints be loosened to enable increased hydroelectricity generation during an energy crisis? Should hydropower operators consistently maintain buffer storage in case of a major urban water crisis? When are the public and/or private benefits of one service outweighed by another? How can water be reallocated across different services to meet social objectives? These are just some of the many regulatory challenges that need to be addressed for multipurpose hydropower reservoirs to sustainably provide water services under the risks and uncertainty associated with climate change and the renewable energy transition.

There are four key implications of the dynamic trade-offs between hydropower companies and the beneficiaries of water services from multipurpose reservoirs. First, multipurpose operations need to be secured through flexible regulation. In other words, the social benefits of additional water services from hydropower reservoirs won't materialise just because they can; governance reforms will be required. Second, trade-offs need to be understood to inform decisions on how water should be reallocated. Hence, the economic costs and benefits of alternative water allocation regimes need to be estimated. Third, dynamic risks demand dynamic risk management. Decision-making on how to invest in and regulate multipurpose hydropower reservoirs will require tools that accommodate random variables, such as water supply and electricity prices, and, importantly, the feedback effects that occur when trying to regulate a complex system (see Page 2015). Finally, neither quantitative nor qualitative analysis alone would be sufficient to identify, test, and implement the reforms needed to realise the potential water security benefits of the current hydropower boom. A hydro-economic model can usefully provide insights on key linkages between hydropower system components, but it cannot explain the origins of stakeholders' preferences and values. Equally, competing stakeholder perceptions of the value of different water or energy services do not provide the foundation for trade-off determination that is offered by economic valuation methods.

Economic analysis has long been a feature of water resources management and governance. The practice of cost-benefit analysis emerged from the water development projects of the U.S. Army Corps of Engineers in the 1950s (Pearce 1983). The field of water resources systems analysis began in the 1960s through interdisciplinary analysis of multi-objective water infrastructure investments across economics, engineering, political science, and hydrology (Brown et al. 2015). Today, there is an abundance of water systems analysis that develops and applies new modelling approaches and decision support tools for water planning problems (see Brown et al. 2015; Castelletti et al. 2008; and Harou et al. 2009 for reviews). A large subfield of this work has estimated the economic costs and benefits of alternative approaches to hydropower governance and reservoir regulation (e.g. Edwards et al. 1999; Foster et al. 2015; Guisández et al. 2013; Harpman 1999; Kern et al. 2017; Kotchen et al. 2006; Maas et al. 2017; Tilmant et al. 2009). In an increasingly complex world, however, this quantitative modelling constitutes just one step, albeit a very valuable one, in the process of integrating applied research into decision-making.

Water resources and their governance increasingly provide linkages for the transmission of risks and uncertainty across interconnected social, ecological, and economic systems. The probabilities of future variables are more uncertain and the impacts of decisions more difficult to estimate. In this context, water resources modellers need to consider the social impacts of planning decisions (Loucks 2017), and engage with decision-making processes in a structured way. Complex water governance problems need to be addressed through multi-stakeholder participatory processes (Grafton 2017). Participatory water modelling is increasingly used by engineers, earth scientists, and interdisciplinary researchers to support water governance (e.g. Daniell 2012; Döll & Romero-Lankao 2017; von Korff et al. 2012), but there is a large gap between the economic theory and modelling of water resources regulation and real-world decision-making; the prevalence of sub-optimal water tariffs is a prominent global example (see Grafton et al. 2014; Johansson et al. 2002; Young & Whittington 2016). Bridging this gap between theory and practice can be achieved by connecting technical hydro-economic modelling with qualitative institutional analysis *and* participatory processes that enable decisions-makers to utilise research results.

This thesis argues that governance reforms are required for hydropower reservoirs to sustainably provide water services under future risks. In addition to outlining the case for reforms, I analyse the design of a particular reform and demonstrate how, in practice, that analysis could be integrated into water governance. The research methods encompass quantitative modelling, qualitative analysis, and participatory approaches; fundamentally, the thesis is an interdisciplinary study with an applied economics foundation. First, I show that flexible regulation is required to manage dynamic trade-offs between hydropower companies' profits and water users' welfare; to this end, I propose three potential reforms that could complement conventional governance instruments. I then provide insights from an applied research project on managing complex water risks in Vietnam to demonstrate how the economic modelling and institutional analysis in the thesis could be incorporated into hydropower reforms. I proceed by examine one of the proposed hydropower reforms in detail: pricing of irrigation water services to reflect foregone electricity generation. I develop a hydro-economic model of multipurpose hydropower operations and governance to examine the conditions under which pricing regulates irrigation water provision more efficiently than a fixed quota under water security and energy market risks. Finally, I adapt the hydro-economic model to evaluate alternative water tariff designs under an electricity supply obligation and estimate the cost of price stability controls.

The thesis examines four primary research questions corresponding to the four core Chapters that are summarised in detail further below:

a) What hydropower governance reforms could enable multipurpose operations under risks? (Chapter 2)
b) How can applied research on water governance reforms be integrated into real-world decision-making? (Chapter 3)
c) When does water pricing allocate water more efficiently than fixed irrigation quotas under risks? (Chapter 4)
d) What is the optimal design of irrigation water tariffs for hydropower governance in the presence of an electricity supply obligation and electricity price spikes? (Chapter 5)

Chapter 2 reviews hydropower governance in order to identify and outline governance reforms that enable the delivery of multipurpose operations. This Chapter shows that conventional regulatory instruments are under-equipped to manage the risks emerging from water and energy systems. These risks are creating: (i) dynamic shifts in the benefits provided by energy and water services, and (ii) dynamic trade-offs between hydropower profits and water users' welfare. I define a conceptual approach to the resilience of multipurpose reservoir systems to show that 'hydropower resilience' requires dynamic water reallocation. I propose and evaluate three potential reforms that could support efficient and equitable provision of water services by profit-motivated operators of multipurpose hydropower reservoirs: (i) periodic relicensing, (ii) water pricing, and (iii) climate/green performance bonds.

Chapter 3 demonstrates how the quantitative modelling and institutional analysis in the thesis can be integrated into real-world decision-making. This Chapter presents a causal approach to the participatory assessment and management of risks to complex food-energy-environment-water systems. I show how this approach was piloted in an applied research project working with local government officials in Lam Dong Province, Vietnam. I describe the water governance context, including the proposed reforms to irrigation water pricing. I draw on the results of that project to provide general insights on how researchers can facilitate water governance reforms.

Chapter 4 examines the efficiency of using either irrigation water pricing or fixed irrigation quotas to allocate multipurpose reservoir storage under risks. Specifically, I seek to better understand the conditions under which regulators may consider adopting water pricing to increase the total benefits of reservoir operation across hydropower and irrigation. Or, on the other hand, I seek to identify when water pricing does not provide relative efficiency gains compared to the guaranteed provision of a fixed volume of water to irrigators. I use stochastic dynamic programming to solve a model of a multipurpose hydropower reservoir where there are stochastic shifts in both the marginal cost and marginal benefit of irrigation water. I extend this basic model to analyse risks across water supply, water demand, electricity prices, and energy policy. I find that the total benefits of reservoir operations are consistently higher under water pricing. In particular, pricing is a superior instrument for allocating water between energy and water services under shifting water demand, water scarcity, and policy-driven level shifts in hydroelectricity revenues. However, fixed quotas may be sufficient where they: (i) provide a central estimate of the variable demand for and opportunity cost of water services provision, or (ii) can be updated to reflect the dynamic values of water and energy services.

Chapter 5 estimates the costs of prioritising price stability in the design of water tariffs for irrigation extractions from multipurpose hydropower reservoirs. I adapt the hydro-economic model developed in Chapter 3 to compare outcomes from: (i) a price stability tariff wherein the volumetric price is averaged over several periods and there is a fixed water scarcity premium; and (ii) a dynamic tariff structure that estimates the marginal user cost of water extraction and includes a water scarcity premium that is contingent on expected storage levels. In order to develop the price stability and marginal user cost tariffs, I draw on current and previous iterations of the tariff structure used in one of the first real-world applications of water pricing to the governance of multipurpose hydropower reservoirs (see Hydro Tasmania 2015, 2017a, 2018). I simulate the application of these tariff structures to water allocation and estimate the relative costs of deploying price stability controls across: (i) foregone hydropower profits, (ii) foregone hydroelectricity generation, (iii) additional electricity purchases by the hydropower company (to meet an electricity supply obligation), and (iv) the reduced efficiency of water allocation (i.e. the reduced total net benefits of water use). I estimate these costs and compare them to the benefits from the indirect subsidy of irrigation water provision by price stability controls. A methodological contribution of this Chapter is a heuristic for incorporating the intertemporal opportunity costs of water provision into water tariff design.

Chapter 6 concludes with: (i) a summary of the main findings and the primary contributions of the thesis to the academic literature; (ii) the research and policy implications of the research; and (iii) an agenda for future work.

Chapter 2

Reforms for Resilience: How to Make 'Multipurpose Hydropower' a Sustainable Outcome

2.1. Introduction

The contemporary hydropower boom is regularly framed as an era of sustainability wherein negative impacts can be minimised and benefits shared (e.g. ADB/MRC/WWF 2013; ICPDR 2013; IEA 2012; IFC/TNC 2017; IHA 2017; MRC 2010; Rex et al. 2014; TNC 2014). Central to this outlook are the multiple services that hydropower projects can provide (e.g. Branche 2015) and the capacity for multipurpose reservoirs to make major contributions to global challenges across water security, energy access, and climate change (e.g. Grey & Sadoff 2007; IEA 2012; Muller et al. 2015; Tortajada 2014). Yet multipurpose hydropower reservoirs cannot generate 'win-win' situations all the time. Supplying water for irrigation, controlling floods, and managing environmental impacts will often involve opportunity costs: foregone revenues from constraints on electricity generation and/or additional capital costs due to fish passages, multiple water outlets, higher dam walls, and other infrastructure modifications (Edwards et al. 1999; Harpman 1999; Jager & Bevelhimer 2007; Zeng et al. 2017). The *capacity* for hydropower operators to deliver water services does not equate to their actual *provision*. Acute trade-offs can emerge between hydropower profits and other water users' welfare. Securing finance for multipurpose water infrastructure is challenging (Naughton et al. 2017). Despite growing calls for 'hydropower resilience' (e.g. Hellmuth et al. 2017; IHA/World Bank 2017; DOE 2016; World Energy Council 2015b), there is limited consideration of the regulatory settings needed to ensure that hydropower companies' resilience management decisions support the resilience of the broader social-ecological system affected by their operations.

In practice, achieving sustainable, multipurpose operations will require governance instruments that provide hydropower companies with the discretion and/or obligation to efficiently and equitably deliver both energy and water services. Prevailing regulatory instruments typically set constraints that support the minimum delivery of water services, including environmental protection, and afford limited scope to adjust the delivery of those services in response to shifts in their value to water users. This static, minimalist approach will not provide regulatory agencies and hydropower operators with the capacity to manage emerging risks from climate change, population growth, and the full array of trends and shocks affecting water supply and water demand globally. Further, the value of hydroelectricity is changing in unpredictable ways with the uptake of variable renewable energy, the development of new energy technologies and business models, and reforms of energy and climate policies. Under these dynamic conditions, profit-motivated hydropower companies cannot be expected to voluntarily adjust operations to maximise social benefits from water services; in general, they will have been granted the right to manage water to maximise their private profits from selling electricity. The requisite incentives and information need to be provided through better regulation. Otherwise, concentrating demands for multiple services on a single reservoir risks undermining the resilience of connected social, economic, and ecological systems to the challenges that prompted contemporary championing of multipurpose hydropower development in the first place.

This Chapter reviews hydropower governance in order to identify and outline regulatory reforms that enable the delivery of multipurpose operations under water and energy risks. Or, in other words, the purpose is to find ways to make 'multipurpose hydropower' a sustainable outcome from operations that consistently and flexibly deliver social benefits, and not an aspiration that is only achieved under favorable conditions. First, I show that conventional governance instruments are under-equipped to manage the emerging risks, or 'events with uncertain consequences', that are creating dynamic shifts in and, in some cases, trade-offs between the benefits provided by energy and water services. Second, I outline a conceptual approach to the resilience of multipurpose hydropower projects – where resilience is an attribute of a social-ecological system composed of three characteristics: resistance, recovery time, and robustness (Grafton et al. 2019) – and show that, in a broader social context, 'hydropower resilience' requires dynamic water reallocation. Third, I evaluate potential reforms that could support efficient and equitable provision of water services by profit-motivated operators of multipurpose hydropower reservoirs.

Section 2.2 reviews the many water and energy services that can be provided by multipurpose reservoirs, conventional instruments for hydropower governance, and risks to hydropower systems from water insecurity and energy transitions. Section 2.3 demonstrates the connection between water reallocation and the resilience of multipurpose hydropower systems. Section 2.4 offers three potential reforms that complement existing institutional frameworks: (i) periodic relicensing, (ii) water pricing, and (iii) climate/green performance bonds. Section 2.5 concludes by outlining steps to develop and test the proposed reforms.

This Chapter focuses on medium- to large-scale hydropower projects (i.e. >100 MW of installed generation capacity) with the capacity for inter-seasonal storage and the provision of water across multiple purposes, but where hydroelectricity generation is the primary purpose. Further, the analysis concentrates on projects that are operated with profit objectives by private companies or state-owned enterprises and are thereby subject to regulation by government agencies acting in the public interest.

2.2. The Governance of Multipurpose Hydropower Operations Under Risks

2.2.1. Multipurpose Hydropower Operations

The impoundment of water creates opportunities for hydropower dams to deliver a range of services. Reservoir storage and downstream flows can be managed to provide water supply and storage for farmers, households, industry, and other water users located downstream or adjacent to hydropower reservoirs (Branche 2015). Multipurpose reservoirs can provide downstream flood protection (Bonnet et al. 2015), flush downstream water pollution and saline intrusion (Jager & Smith 2008), and regulate rivers to facilitate boat navigation and inflows to downstream reservoirs. Reservoirs and regulated rivers also provide recreational opportunities, such as kayaking and fishing, that can have high economic value (Bonnet et al. 2015; Branche 2015).

Globally, around 30% of large dams are officially registered as multipurpose, with approximately 3900 of these including hydropower as one purpose (Naughton et al. 2017). Water-based services have long been a motivating factor for hydropower development, and their economic value can exceed that of energy production for many reservoirs (Bonnet et al. 2015). Water management services may emerge over time even if they are not valued and planned in the original design of hydropower projects (IEA Hydropower Agreement 2017). Proponents of system-scale, multipurpose approaches to hydropower development have proposed that, if designed correctly, planned investments in new and existing hydropower projects could generate US $285 billion to US $770 billion per year in additional water services at the global scale (Opperman et al. 2017).

The negative environmental and social impacts of hydropower dams and reservoirs are well-documented (e.g. WCD 2000; Jager & Smith 2008). Dams are physical barriers to the natural flow regimes of rivers (Poff et al. 1997), obstructing the migration of fish and other aquatic species, as well as the transport of nutrients and sediment (Krchnak et al. 2009). These alterations modify the ecology and geology of both downstream and upstream areas, reducing the productivity of natural systems that provide ecosystem services to communities and economic sectors (Olden et al. 2010). Importantly, impacts can occur hundreds of kilometers downstream from dams (McCartney 2009). Hydropower projects have frequently affected the livelihoods of riparian communities in both the short- and long-term, including groups that are the focus of industry best-practice resettlement and livelihood support schemes (e.g. Shoemaker & Robichaud 2018).

However, in some cases, dam infrastructure and operations can be modified to restore or avoid disrupting elements of the downstream flow regime or upstream water level fluctuations, thereby reducing the environmental and social costs of dam operation and supporting the provision of ecosystem services by regulated rivers to water users (Krchnak et al. 2009; Poff & Schmidt 2016; Richter & Thomas 2007; Watts et al. 2011). Hence, the reoperation of existing dams to support environmental flows,[1] cultural flows,[2] and reservoir-based ecosystem services can be an important water service provided by hydropower reservoirs.[3]

Hydropower reservoirs store potential energy. Hydroelectric power production can be ramped up and down rapidly, from zero to maximum or partial capacity and vice versa, by changing the intake of water to turbines. The flexibility to adjust generation within minutes means that hydroelectric

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[1] Environmental flows are "the quantity, timing, and quality of water flows required to sustain freshwater and estuarine ecosystems and the human livelihoods and well-being that depend on these ecosystems" (IRF 2007).

[2] Cultural flows are understood here as water entitlements legally and beneficially owned by First Peoples that are of a sufficient and adequate quantity and quality to improve the spiritual, cultural, environmental, social, and economic conditions of those First Peoples (adapted from National Cultural Flows Project 2018).

[3] Here, I consider the partial restoration of environmental and cultural flows as a 'water service' in order to define a simple typology that facilitates analysis later in the Chapter. It is important to recognise, however, that a reduction in the environmental and social costs of a hydropower project does not necessarily equate to a creation of benefits and is not, per se, an additional purpose given that those costs are a result of the project being built in the first place. Further, the appropriate perspective on whether avoided costs constitute a benefit or service depends on the timescale of the project and how ecosystems and communities have adapted to the project. For example, partial restoration of spring pulse flows to an alpine river is probably a legitimate water service in the context of an 80-year old dam, but limiting the disruption of pulse flows by a new dam is probably not. On the other hand, restoring pulse flows to an aquatic ecosystem already adapted to an altered flow regime may not be a 'water service' if it undermines new ecosystem services.

power plants can provide a range of energy services to electricity networks. These services include: frequency and voltage control, maintaining spare capacity to support system-wide security and reliability, and 'black-start' capacity to initiate the restoration of failed network interconnections (IEA Hydropower Agreement 2017; World Energy Council 2015a). Globally, the value of these ancillary energy services is rising along with the increasing penetration of variable renewable energy technologies. Further, the transition of electricity systems from 'baseload' modes (e.g. coal-fired or nuclear power plants that are never switched off) to 'base-cost' modes (e.g. solar and wind plants with zero-marginal cost that generate variable levels of electricity) is changing how hydropower projects provide energy services. For example, improved market- and regulation-based incentives to provide 'firming capacity' for new solar and wind plants is creating incentives for investment in pumped storage hydropower facilities (Ela et al. 2013).

Figure 2.1 illustrates the array of energy and water services that multipurpose hydropower projects can provide. These services may involve all types of goods and resources across the spectrum of ownership and access: (i) private goods where consumption is rivalrous and excludable (e.g. water supply for irrigation); (ii) club goods where consumption is excludable but non-rivalrous (e.g. electricity grid reliability); (iii) common-pool resources where consumption is non-excludable and rivalrous (e.g. fisheries or recreation in public spaces); and (iv) public goods where consumption is non-excludable and non-rivalrous (e.g. navigation). Note that whether a particular service belongs to one of the above categories can depend on the context, e.g. urban water could be a private good if a household's access is conditional on paying charges, but a common-pool resource if access of all households is provided via full public subsidies. For all services, there may be indirect benefits and costs for third parties, or 'externalities', generated across economic sectors and geographic scales. For example, secure urban water supplies during droughts can reduce waterborne disease and improve long-term health and educational outcomes for children. On the other hand, damages to fisheries caused by dam construction could generate food insecurity and lead to rural-urban migration. Further, the provision of particular services may be complementary (e.g. downstream irrigation and hydropower generation) or rivalrous (e.g. environmental flows and flood control). In short, hydropower projects can generate many services and externalities that affect a wide range of water users and other groups in different ways. Hence, multipurpose reservoirs comprise a central focal point of a social-ecological system encompassing a broad geographic scale.

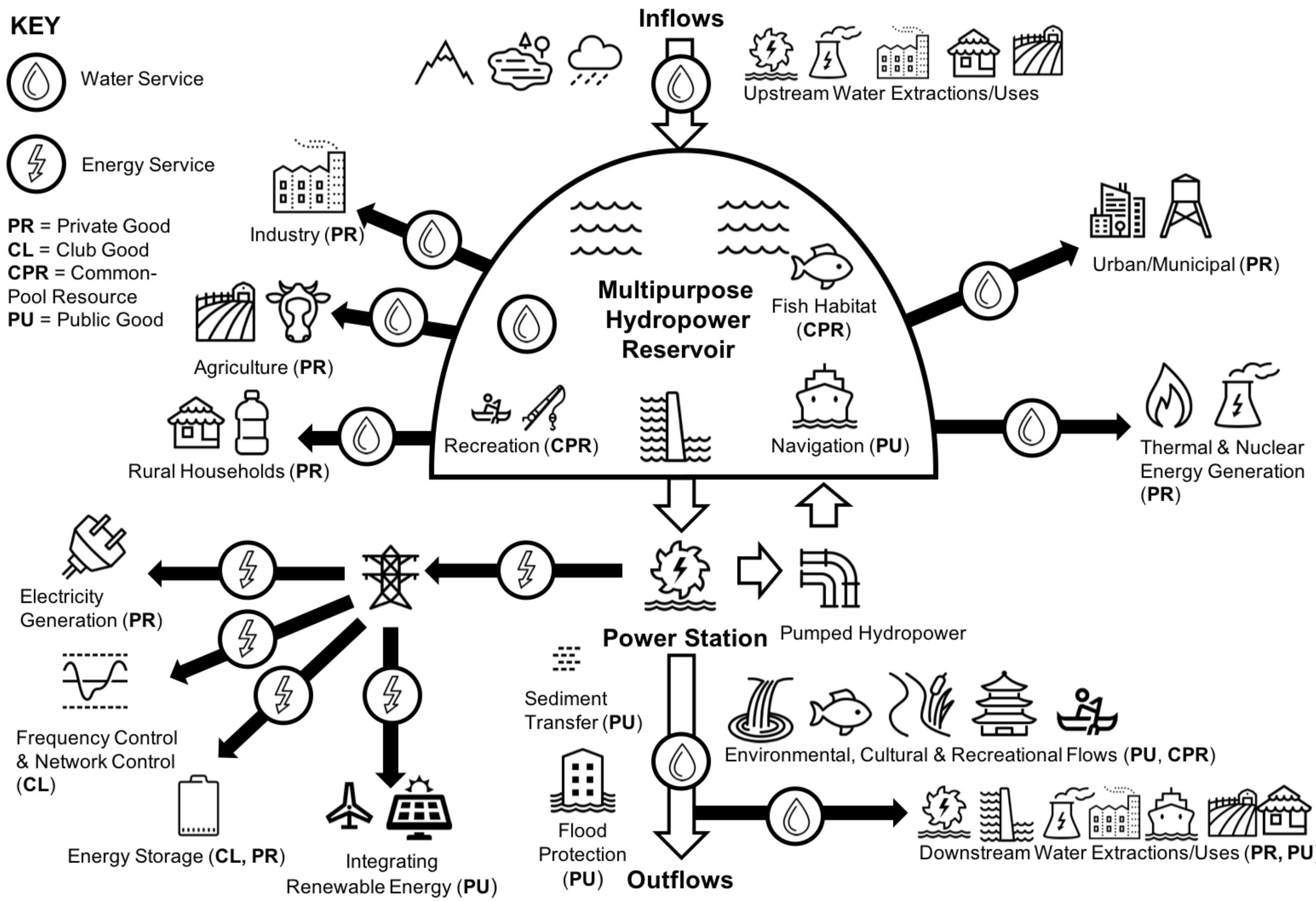

Figure 2.1. The potential water and energy services provided by a multipurpose hydropower reservoir.

2.2.2. Instruments for Hydropower Governance

The decision-making of private companies and state-owned enterprises operating hydropower dams is ultimately focused on the maximisation of profits and/or electricity generation. Providing water services, minimising negative externalities, and operating reservoirs across multiple purposes can often involve additional costs or foregone revenues (Krchnak et al. 2009). Reconciling divergent private and public interests is the role of governance institutions and regulations that integrate the welfare of all water users and society at large into hydropower operations. Further, constraints on and incentives for particular operating modes also facilitate opportunities for complementary uses of water, such as scheduling downstream releases to support productivity of downstream ecosystems.

Here, we understand hydropower governance as the structures and processes through which public and private actors interact to regulate the development and management of hydropower projects. Below we review four prevalent instruments for the governance of hydropower dams and reservoirs: (i) licenses and permits, (ii) flow and storage regulation, (iii) safeguard policies and conditional finance, and (iv) voluntary standards and corporate social responsibility initiatives. These instruments are often deployed in tandem as they are complementary, cover both formal and informal institutions, and have different strengths and limitations.

License and Permits

License and permit regimes confer upon a hydropower company the legal right to: (i) plan, build, and operate a hydropower dam project; (ii) generate and dispatch electricity, and (iii) utilise and manage water resources, subject to conditions enforced by a regulatory agency or agencies. Water and energy licenses are used to regulate hydropower projects in many countries, such as the United States, Australia, Brazil, China, and Nepal (IFC 2015; Pittock & Hartmann 2011); permits or licenses are often required from multiple government agencies. Arrangements differ across jurisdictions, but a permit or license application process generally requires an environmental and social impact assessment (ESIA) that demonstrates how negative externalities and water services will be incorporated into project design and operation, as well as the project's compliance with relevant domestic legislation regarding, for example, water pollution, endangered species protection, and, in some cases, international law (IFC 2015). Review of ESIAs provides an opportunity for public and private stakeholders to specify infrastructure modifications or operating rules that are conditions for license or permit approval.

Licenses typically stipulate fixed operating constraints across the decades of a project's lifetime, unless relicensing provisions are specified for a certain date or there is a change in domestic legislation. Long-term certainty serves two important purposes: (i) hydropower operators and project financiers need to estimate project costs and revenues prior to making investment decisions, and (ii) water users and regulators need to make water management and planning decisions with reference to expected dam operations. Renegotiating conditions with both project operators and stakeholders can involve large transaction costs. For example, the relicensing of privately-operated hydropower dams under the Federal Energy Regulatory Commission (FERC) in the United States has typically required 5-7 years of consultations and negotiations to renew a 30-50 year license (Kosnik 2013; Madani 2011). The status quo in most jurisdictions is that license conditions are fixed for many decades (Pittock & Hartmann 2011). This is a problem because licenses and permits are a minimalist approach to regulation: they provide boundaries for profit-oriented operation decisions, but do not facilitate the socially optimal provision of a range of water services as conditions change. Important global challenges, such as food and water insecurity, are emerging more quickly than a license adjustment every 30-50 years could accommodate, and if fixed, long-term licensing conditions remain the status quo then the opportunity will not be fully realised for new multipurpose reservoirs to address new challenges as they arise. Further, adherence to licensing conditions during operations is not guaranteed: a breach may trigger a regulatory agency to impose a fine or other punishment on the hydropower operator, but the strength of monitoring and enforcement depends on the institutional capacity of the regulator and the political will of the government.

Constraints on Downstream Flows and Reservoir Levels

Constraints on downstream flows and reservoir storage levels may be included in a water license (Krchnak et al. 2009). Typical forms of regulation include minimum flows and/or reservoir levels, maximum flows and/or reservoir levels, and ramping rate restrictions. The latter define a maximum rate of change in flow or water level over a short time span, such as minutes or hours, to prevent erosion and other damages associated with rapid fluctuations. Minimum and maximum flows are generally expressed in terms of instantaneous releases (i.e. cubic metres per second), although longer time spans may be possible, such as the total volume of downstream releases across a day or week. Minimum/maximum reservoir levels are typically defined with reference to specific water services, such as the spare capacity required to absorb a flood event of a particular size. 'Run-of-river' operations set reservoir outflows equal to inflows on an hourly to weekly basis; this is a common example of flow regulation in the United States (Jager & Bevelhimer 2007). Water licenses or formal and informal agreements with other water users may stipulate minimum or maximum storage levels at particular times of year to provide downstream flood protection, sustain fish habitat, ensure the availability of storage for water extractions, and support other activities associated with multipurpose reservoirs. Release schedules can be defined to mimic specific aspects of the natural flow regime; for example, Snowy Hydro in Australia schedules one 2-day flushing flow event and four 8-hour high flow events for the Snowy River during spring to partially replicate natural snowmelt (Snowy Hydro 2018).

It is important to recognise, however, that constraining the optimisation of profits (by hydropower operators) to create social benefits (across all water users) is not the same as maximising benefits across all water and energy services. Once again, operating constraints represent a minimalist approach to regulating hydropower operations. Although they can be altered when major shifts occur in operating regimes (see Hydro Tasmania 2013), flow and storage constraints do not provide real-time incentives nor information for hydropower operators to manage multipurpose reservoirs across the full range of potential services and externalities.

Conditional Social and Environmental Safeguards

Social and environmental safeguards set out systems of policies and procedures that can apply to both financiers and borrowers. Adherence to these policies and procedures is a condition of finance being approved and a project proceeding. Relevant instruments include: (i) the safeguard policies of multilateral development banks (ADB 2009; World Bank 2016b); (ii) guidelines for export credits, or loans, from rich countries to developing countries (OECD 2017); and (iii) safeguards and conditions associated with carbon markets and funds, such as the Clean Development Mechanism (Soanes et al. 2016), the European Union Emissions Trading Scheme Linking Directive (European Union 2004), and the Green Climate Fund (GCF 2018). A reference point for the development and implementation of these safeguards are the strategic priorities, policy principles, and technical guidelines developed by the World Commission on Dams (2000) and subsequent initiatives, such as the Hydropower Sustainability Protocol (which is discussed in the following sub-section). However, the growing prominence of lending institutions from China and other major emerging economies as alternative, and less conditional, sources of finance has diminished the prevalence of multilateral safeguards in the governance of new hydropower projects (Skinner and Haas 2014).

An example of a safeguard system is the World Bank's Environmental and Social Framework that has been implemented since 2018. Bank staff are required to: (i) classify a potential project's risks, (ii) conduct due diligence on the project prior to financial approval, (iii) support the borrower to monitor the project's performance across social and environmental considerations, and (iv) publish information publicly (World Bank 2016b). Under the framework, borrowers are required to: (i) conduct an ESIA to identify stakeholders and risks, (ii) develop an environmental and social commitment plan, and (iii) establish monitoring regimes and a grievance mechanism for water users and other stakeholders (World Bank 2016).

The regulatory capacity of financial safeguards is focused on the beginning of a project before finance has been approved (Skinner and Haas 2014). Unforeseen externalities, services, and trade-offs may be identified by safeguard policies during the operation of a project, but borrowers are not necessarily compelled to address their full extent unless other regulatory instruments are in force. Project financiers, on the other hand, have limited control over whether their investment meets social and environmental standards during operations. In essence, safeguards set minimum social and environmental outcomes from a hydropower project: they provide the means to avoid the worst outcomes, but not the means to approach the full scale of social benefits that a multipurpose project could deliver.

Voluntary Standards and Corporate Social Responsibility Initiatives

Voluntary standards and corporate social responsibility (CSR) initiatives are self-regulation instruments and tools that can be implemented by hydropower project developers and/or financiers in partnership with industry associations and non-government organisations. Examples include the Equator Principles (2013) for banks to manage environmental and social risks, technical guidelines issued under annexes of the International Energy Agency's Hydropower Agreement (2016), water stewardship initiatives (e.g. WWF/M&S 2017), and partnerships between hydropower companies and non-government organisations to restore natural flow regimes (e.g. Opperman et al. 2011).

A prominent voluntary instrument is the Hydropower Sustainability Assessment Protocol (HSAP) developed by the International Hydropower Association (IHA) in collaboration with industry, lenders, civil society, and governments (IHA 2018a). The Protocol supports the independent assessment of performance across environmental and social sustainability topics at different project stages. Assessors assign quantitative scores and qualitative comments across a range of categories, with the results providing a basis for hydropower operators to assess their performance, identify improvements, and monitor outcomes over time. Both participation and the publication of results are voluntary. The Protocol is complemented by the Hydropower Sustainability Guidelines on Good International Industry Practice Guidelines (GIIP) (Locher & Costa 2018) that define the processes, outcomes, and measures related to sustainability in the hydropower industry.

A particular strength of the Protocol, GIIP, and other CSR instruments is that they present an approachable entry point for hydropower operators to gather information, better understand the social and environmental externalities they generate, and find ways to improve operations and support other water users. The absence of enforcement and a focus on generating information mean that voluntary approaches are very adaptable to changing circumstances. Self-regulation through CSR instruments can be an important avenue for hydropower companies to obtain and maintain the informal social license to operate under the prevailing set of formal regulatory instruments. But voluntary approaches to environmental regulation cannot incentivise private actors to deliver first-best social outcomes on their own: the prospect of some accompanying cost provided by external regulation (e.g. a tax, removed subsidy, or some other penalty) is necessary for voluntary approaches to incentivise efficient levels of self-regulation (Segerson & Wu 2006). Hence, voluntary standards and CSR initiatives are valuable tools to generation information and support stakeholder dialogue, but they will not, and indeed are not designed to, provide hydropower operators with the discretion to fully incorporate water services and other externalities into their real-time decision-making.

Table 2.1 summarises the governance instruments outlined above, including stages of a hydropower project where they are applicable, the approach to regulation they embody, and the likelihood of compliance and capacity for enforcement.

		Project Stage				
Instrument	**Regulator/ Implementing Partner**	*Plan*	*Construct*	*Operate*	**Regulatory Approach**	**Compliance & Enforcement**
Licenses & permits	Government Agencies	✓	✓	✓	Assign right to use water resources and generate electricity within fixed boundaries; Constraints on water use and electricity production rights	High/Medium (Conditional on institutional capacity)
Flow & storage constraints	Government Agencies, Self-regulation	✗	✓	✓	Delivery of minimum water services; Operating boundaries	High/Medium (Conditional on institutional capacity)
Conditional safeguards	Financial institutions	✓	✗	✗	Specify minimum social and environmental outcomes	High (During planning stage)
Voluntary safeguards	Self-regulation, Industry, Non-government organisations	✓	✓	✓	Information generation; Stakeholder dialogue	Self-regulating

Table 2.1. Classification of hydropower governance instruments.

2.2.3. Water Security Risks and Energy Market Risks

There are many financial, economic, regulatory, social, and environmental risks associated with hydropower projects. Flood control provision by dams can create a false perception among downstream land users of complete protection from extreme flood events (Etkin 1999). The regulation of rivers may provide economic opportunities for downstream projects, such as irrigation and thermal power plants, that were not originally planned (Branche 2015). Social values regarding the natural environment change over time, causing corresponding shifts in the non-market value of aquatic ecosystem services (Barbour et al. 2016). These and other risks alter the benefits and costs of the energy and water services delivered by multipurpose operations. Hence, they test the capacity of governance instruments to manage trade-offs and synergies between the profits of hydropower companies and the welfare of other water users.

There are many valid approaches to defining and formulating the concept of risk (Aven et al. 2015). Here, I think of a risk as an "event with uncertain consequences" (Wyrwoll et al. 2018). From this perspective there can be both positive and negative consequences associated with a risk and the net impact could be perceived differently by different stakeholders. Below, I consider two key sets of risks in the context of multipurpose hydropower reservoirs: 'water security risks' and 'energy market risks'. The former are formulated in terms of water security being "the availability of an acceptable quantity and quality of water for health, livelihoods, ecosystems and production, coupled with an acceptable level of water-related risks to people, environments and economies" (Grey & Sadoff 2007). In that context, water security risks are caused by variability in water supply and shifts in the demand for water services. Energy market risks are caused by the dynamic economic value of hydroelectricity under energy transitions and temporal variability, between seasons and across decades, in the demand for water to generate energy services.

Water Security Risks

Hydrological variability is a defining challenge of hydropower operations and their governance. Real-time decisions and inter-seasonal planning are required on how much water to store and release when future inflows are unknown. Operating constraints are partially determined on the basis of the expected status of variable water supplies external to a reservoir, such as rainfall and run-off in downstream catchments. In the past, hydropower engineers and regulators estimated key variables on the basis of historical data, such as daily and monthly inflows, probable maximum floods, and year-to-year climate variability. Today, projected hydrological and climatic trends and extremes during the lifetime of new and existing hydropower projects are outside the historical range (Milly et al. 2008). Droughts, storms, and other extreme weather events are increasing in severity and frequency under anthropogenic climate change (IPCC 2013). Changes in upstream water extractions exacerbate uncertainty regarding reservoir inflows. In short, hydrological variability is increasing and becoming more difficult to manage.

Long-term trends in precipitation and temperature due to anthropogenic climate change are projected to substantially alter inflows into hydropower reservoirs (Mukheibir 2013). The direction of these shifts and their implications vary across different regions; for example, potential water availability in hydropower reservoirs has been projected to increase in India, Central Asia, and Central Africa during the 21st century, but decrease in Europe, the United States, East Asia, and southern parts of Australia, South America, and Africa (van Vliet et al. 2016). Climate change may also facilitate erosion and increase the rate at which reservoirs accumulate sediment and lose storage capacity over time (Williams 1989). Increased intensity of high-precipitation events could increase the need for reservoirs to reserve storage capacity for flood control. Reduced snowfall and accelerated glacial retreat will alter the seasonal characteristics of inflows to high-altitude reservoirs (Hartmann et al. 2013; Rheinheimer et al. 2013). These long-term trends will significantly alter the commercial returns from existing hydropower projects (Mukheibir 2013); although the direction and magnitude of these trends can be predicted for particular locations, their realisation cannot be known precisely in advance and, hence, seamlessly integrated into planning and regulation. Importantly, both short-term variability and long-term trends in reservoir inflows affect the trade-offs between energy and water services: when storage is scarce and excess water demand exists, the trade-offs between rivalrous water uses are acute. On the other hand, increased inflows can create opportunities to allocate additional water to one water use without sacrificing benefits elsewhere.

The global demand for freshwater is projected to increase by 55% between 2014 and 2050 under current trends (WWAP 2014). Population growth, urbanisation, rising energy use, environmental pollution, and increasing demand for water-intensive food products are challenging the capacity of governance institutions to balance water supply and demand across many regions of the world (Beddington 2009; Rodriguez et al. 2013). Multipurpose reservoirs can help bridge supply gaps, but need to be operated to accommodate shifting water demand, particularly under climate variability and climate change. During droughts, for example, demand for irrigation extractions from storage may increase to make up for shortfalls in rainfall. Higher water temperatures in rivers and reservoirs increase cooling water withdrawals by thermal electricity plants (Byers et al. 2014). Household electricity demand rises under extreme temperatures, thereby increasing the demand for and economic value of hydroelectricity generation. The failure of alternative sources of supply can amplify the dependence of water users on access to hydropower storage (e.g. RFA 2013). As the demand for and value of allocating water across different uses and users of a multipurpose reservoir shift, so do the costs and benefits of the operation decisions and water allocations determined by the overlying governance regime. In other words, the value of different water services is dynamic and, once again, can be projected but not known perfectly in advance.

Summarising the discussion above, we can conceive the following water security risks that relate to the management and governance of multipurpose hydropower systems:

(W1) A short-term, stochastic shift in reservoir inflows due to climate variability or shifts in upstream water use or land management. Occurs over a daily to annual timescale;

(W2) A long-term, stochastic shift in reservoir inflows due to climate change or long-term trends in upstream water use or land management. May emerge as a trend or level effect within a multi-annual to decadal timescale;

(W3) A short-term, stochastic shift in the demand for and value of a water service or set of water services. Occurs over a daily to annual timescale;

(W4) A long-term, stochastic shift in the demand for and value of a water service or set of water services. May emerge as a trend or level effect within a multi-annual to decadal timescale;

Table 2.2 summarises these water security risks and their potential causes. Note that (W1) and (W2) relate to the supply of water to a reservoir, and (W3) and (W4) relate to the demand for water services which can also be a function of broader water supply conditions. For example, a single drought could pose multiple risks that need to be managed in a multipurpose hydropower reservoir system providing irrigation water: decreased inflows that reduce overall storage levels and total water supply for both purposes (W1), plus increased demand for irrigation water extractions due to less direct rainfall on cropland (W3).

Energy Market Risks

Hydropower revenues vary significantly over time. In liberalised electricity markets – where multiple generators bid into competitive markets – the marginal value of generation is determined by market demand and supply conditions that vary across sub-daily to seasonal time scales. Over the longer term, a range of factors affect marginal and total revenues, including coal and gas prices, the retirement and entry of other power stations that can ramp production up and down at a similar rate, and the trajectory of energy demand under economic, population, and technology trends. Secondary markets for ancillary energy services open up new revenue opportunities. Energy market liberalisation and other reforms shift pricing structures. Hydropower revenues can also vary in regulated markets – where a central operator determines prices and dispatch quantities – according to the shifts in the merit order for dispatch and the parameters for regulated returns or retail tariffs.

Amplifying this periodic revenue variability is a fundamental disruption occurring globally: the transition toward decarbonised energy systems. This shift poses both opportunities and challenges for hydropower companies (Gaudard et al. 2016). On the one hand, the capacity to dispatch and store renewable energy offers the prospect of higher marginal revenues in markets where increasing penetration of intermittent renewable generation technologies coincides with: (i) rising or stable demand for centralised generation; (ii) markets for generation capacity, frequency response, and other ancillary services; and (iii) carbon pricing making hydropower more competitive than natural gas as a flexible generation technology. On the other hand, the long-term competitiveness of large storage reservoirs could be undermined by: (i) increased penetration of technologies for distributed energy generation (e.g. rooftop solar photovoltaic systems), distributed transmission (e.g. micro-grids), and distributed storage (e.g. household batteries and electric vehicles); (ii) falling peak prices in liberalised markets as competing forms of electricity storage fall in cost and are more widely deployed (e.g. off-river pumped hydropower, large-scale batteries, thermal concentrated solar power storage systems, and hydrogen fuel cells); and, (iii) adoption of demand-side management technologies.

A further complication for hydropower companies from the energy transition are the government policies driving it. Renewable energy certificates (RECs) and carbon offset credits (COCs) have previously been a key source of income for hydropower projects at the national and international levels (Soanes et al. 2016). RECs and COCs can be accredited for the generation of renewable energy and sold by hydropower companies or project financiers to entities complying with obligations to reduce carbon emissions or use renewable energy, such as companies participating in the European Union Emissions Trading Scheme or energy retailers subject to Australia's Renewable Energy Target. Like any market instrument, the price of RECs and COCs vary according to demand and supply shifts. Compliance markets often have defined beginning and end points, but the underlying targets and parameters may be changed. Hence, policy shifts can cause both predictable price shifts (e.g. the traded price for certificates falling to zero when a target is met or a scheme is ending) and uncertain price shifts (e.g. a cap being placed on the eligibility of certain types of credits when a scheme is already running). The introduction of carbon pricing and other climate change mitigation policies can have similar level effects on the value of hydroelectricity.

The exact trajectory of decarbonised energy systems is truly uncertain, meaning that it is not possible to assign probabilities to particular forecasts of what future energy systems will look like. But, from a hydropower company's perspective, their impact at any point in time is embodied in market prices and, hence, the revenues from dispatching hydroelectricity. Importantly, shifts in the value of allocating water to electricity generation alter the opportunity cost of hydropower operators' allocating water to the provision of water services (Kern & Characklis 2017). For example, if the wholesale electricity price increases then the foregone profits from a fixed extraction of irrigation water would also increase. On the other hand, if wholesale prices decline then the opportunity costs of irrigation water provision would fall.

Consistent with the discussion of water security above, there are two important types of energy market risks that affect the management and governance of hydropower systems:

(E1) An increase or decrease in the marginal value of hydroelectricity over a specific period. May be a short-term, stochastic change reflecting temporary market conditions (e.g. demand-supply imbalances), or a long-term trend reflecting fundamental shifts in technology and networks; and

(E2) A level shift in marginal hydroelectricity revenues due to a policy change, such as access to a green certificate market being removed or the introduction of a carbon price

Risk type	**Time scale**	**Impact on Hydropower System**	**Potential Causes**
(W1) Short-term stochastic shift in reservoir inflows	Daily to Annual	Alters trade-offs between energy and water services	Seasonal rainfall variability, Extreme rainfall events, Cropping patterns in upstream catchments
(W2) Long-term stochastic shift in reservoir inflows	Multi-Annual to Decadal	Alters trade-offs between energy and water services	Climate change, Climate oscillations, Upstream water infrastructure development, Deforestation/afforestation in upstream catchments
(W3) Short-term shift in demand for water service(s)	Daily to Annual	Alters value of water services	Price fluctuations for commodities and marketed goods, Seasonal rainfall variability,
(W4) Long-term shift in demand for water service(s)	Multi-Annual to Decadal	Alters value of water services	Population growth, Economic growth, Urbanisation, Growth or decline of water-intensive economic sectors or technologies, Changing social attitudes on environmental protection, Investments in alternative sources of water supply
(E1) Increase/decrease in marginal hydroelectricity revenue	Defined time period	Alters value of energy services	Electricity demand/supply imbalances, Cost declines in generation technologies, Natural gas prices, Transport sector electrification, Extreme weather events
(E2) Level shift in marginal hydroelectricity revenue due to policy change	Instantaneous (but may be anticipated or pre-announced)	Alters value of energy services	Carbon pricing introduction/removal, New markets for energy services, Subsidy introduction/removal for alternative generation technologies, Changes to greenhouse gas abatement targets

Table 2.2. A typology of water security and energy market risks.

2.3. Water Allocation and Resilience

2.3.1. Water Allocation and Hydropower Governance

In a multipurpose hydropower system, a water allocation is the pattern of water use across different services and associated water infrastructure at a specific time (see Grafton et al. 2017 for a general version of this definition).[4] Hydropower governance instruments influence the use of water by hydropower companies and establish formal and informal rights for all water users. Minimum flow requirements, for example, ensure the availability of water for downstream ecosystems and water users at agreed times. Further, the construction and modification of water infrastructure by hydropower companies, such as the height of dam walls or the type of sediment transfer and fish migration technologies, are influenced by governance instruments and affect the delivery of water services. Although other water users control their consumption of available water resources, the final allocation of water across different uses is primarily determined by: (i) the profit-motivated decisions made by the operator within (ii) the boundaries and incentives defined by governance instruments. Drawing on (Grafton et al. 2017; Griffin 2016; OECD 2015a) we can assess the resulting water allocation across three objectives:

- *Allocative efficiency*, an allocation of water at a specific point in time where it is not possible to reallocate water or water infrastructure across different water and energy services to increase the net benefits generated by the hydropower system (i.e. direct benefits to all water users plus positive externalities minus negative externalities);

- *Dynamic efficiency*, an allocation of water across different time periods where it is not possible to reallocate water use and infrastructure to increase the aggregated net benefits generated by the hydropower system;

- *Equity*, an allocation of water at a point in time or across different time periods which is consistent with established norms of distributive justice, perceptions of fairness, and the importance of different water and energy services to society as a whole.

[4] As Grafton et al. (2017) note, in certain water governance regimes a water allocation can refer to the volume of water abstraction that is permitted in a specific time period, subject to pre-defined constraints and rules.

Allocative efficiency is about maximising the aggregate net benefits from using a fixed amount of water at a given time; for example, if an irrigator could theoretically pay a hydropower company more than the foregone energy revenues from providing additional irrigation water and still make a profit, then that reallocation would increase allocative efficiency. Dynamic efficiency is about maximising the benefits of water allocation across time. In addition to managing seasonal or inter-annual inflow variability, this objective also informs the timing of investments to upgrade infrastructure, such as increasing storage capacity to accommodate larger floods or provide additional water supply under droughts.

There are two important points to note regarding allocative and dynamic efficiency. First, the economic benefits and costs of water services can be difficult to measure as many are not traded in markets. Whilst techniques exist to estimate the non-market values of ecosystem services, many of the externalities associated with multipurpose operations, such as national water security, evade real-time measurement. Second, these conventional economic criteria for resource allocation take a neutral view on how benefits and costs should be distributed. For example, they treat one unit of revenue for a subsistence fisherman, a large hydropower company, and a golf course as equivalent contributions to aggregate social benefits. Hence, allocative and dynamic efficiency do not provide a framework for prioritising particular groups or services according to socio-economic disadvantage, historical injustice, or meta-level objectives, such as national food and energy security or endangered species protection. Valuation challenges and distributional considerations are why equity needs to be a stand-alone objective of water allocation. However, the fairness of a given water allocation is subjective and political processes shape how equity considerations are integrated into governance instruments. There may also be trade-offs between equity and the two types of efficiency, and the appropriate balance is, once again, subjective.

Shifts in water demand, water supply, and social preferences are a major driver for water reallocation globally (Marston & Cai 2016). The impetus for sustainable, multipurpose operations motivating this study is indicative of a shift in social preferences regarding the role of hydropower dams and how they should be built and operated. Section 2.2 of this Chapter showed how water security and energy market risks alter the value of and trade-offs between water and energy services. Below, we use the three objectives presented in this Section to outline the need for dynamic water allocation in multipurpose hydropower systems.

2.3.2. Resilience of Multipurpose Hydropower Systems

There are many different ways to define, understand, and deploy the concept of resilience (for reviews see Folke 2006; Levin et al. 1996; Walker et al. 2004). The term has been used to described the capacity of a social-ecological system to deal with change and continue to develop (SRC 2018). Similarly, a resilient system has been described as absorbing and adapting to disruptions by reorganising itself to grow and thrive beyond the pre-disruption level of performance (see Folke et al. 2010; Holling 1973; Levin et al. 1996; Walker et al. 2004). In the hydropower sector, definitions of resilience can be imprecise but generally relate to risks and their management. The World Energy Council (2015, p.10) states that "resilience implies a functioning and stable system", "resilience for energy infrastructure refers to its robustness and ability to recover operations to minimise interruptions to service", and "resilience also implies the ability to withstand extraordinary events". The Climate Resilience Secretariat – a partnership between the hydropower industry and multilateral development banks – is developing guidelines for the sector that define climate resilience as "the capacity of a hydropower project or system to absorb the stresses imposed by climate change, and in the process to evolve into greater robustness" (WBG/IHA/EBRD 2017).

Here, I do not adopt a general definition of resilience. Instead, I adapt a specific approach that is consistent with the observation of Linkov et al. (2014, p. 407) that "resilience, as a property of a system, must transition from just a buzzword to an operational paradigm for system management". The starting point is to integrate the discussion of water and energy risks in Section 2.2 with the approach of Grafton et al. (2019) and conceive of resilience as a specific characteristic of the entire social-ecological system encompassing a multipurpose reservoir (see Figure 2.1). Here, resilience consists of three measurable components:

(R1) Resistance, the degree to which a multipurpose reservoir system's performance changes following an adverse risk event (adapted from Harrison 1979);

(R2) Recovery time, the speed at which the multipurpose reservoir system recovers and returns to a desirable state of functionality or level of performance following an adverse risk event (adapted from Hashimoto et al. 1982; Pimm 1984); and,

(R3) Robustness, the probability of the multipurpose reservoir system to remain functional and not cross an undesirable threshold in the presence of adverse risk events (adapted from Huizar et al. 2018).

Note that (R1) - (R3) concern risk events that have a negative, or adverse, impact on overall system performance and, hence, resilience is considered to be a positive feature of a hydropower system. Section 2 defined risk events in a neutral manner, such that they could lead to positive outcomes, e.g. a long-term increase in reservoir inflows could increase the capacity of a multipurpose hydropower system to deliver both energy and water services.

Managing the risks and opportunities of change through water reallocation is a fundamental task of water governance reform (OECD 2015). Here, the above understanding of resilience is used to show how instruments that enable water reallocation can generate better outcomes under risks and, hence, why governance reforms are needed for multipurpose hydropower projects to achieve their potential benefits. Figure 2.2 illustrates the connection between water allocation and the resilience of a theoretical multipurpose hydropower system[5]. System performance at a specific point in time is a combination of allocative efficiency and equity, with the aggregate net benefits of water allocation across energy and water services weighted by social norms regarding distributional equity (see Adler 2016 for a review of the use of distributional weights in welfare economics). In

[5] Note that the welfare of certain water users within the system encompassing a reservoir, such as downstream ecosystems or resettled communities, may have exhibited greater or less resilience to risk events if dams and other infrastructure were not built in the first place. The hypothetical hydropower system discussed here assumes that a multipurpose reservoir already exists.

this example, I assume that there is a hydropower company with an obligation to maintain storage above a certain level to enable rivalrous irrigation extractions from the reservoir (i.e. water is extracted for hydroelectricity and irrigation from different outlets). There is a theoretical maximum level of system performance where, under perfect information regarding social preferences and the value of energy and water services, completely flexible instruments could reallocate water to maximise the equity-weighted net benefits of water allocation. The time path of the maximum performance level is dynamic because: (i) the benefits and externalities of the different services change under water and energy risks; and (ii) social preferences change regarding the distribution of water over time and under shifts in (i). Note that the area under the time path of system performance provides a measure of dynamic efficiency (weighted by equity considerations) and, for simplicity, I ignore time preferences and the discounting of future benefits.

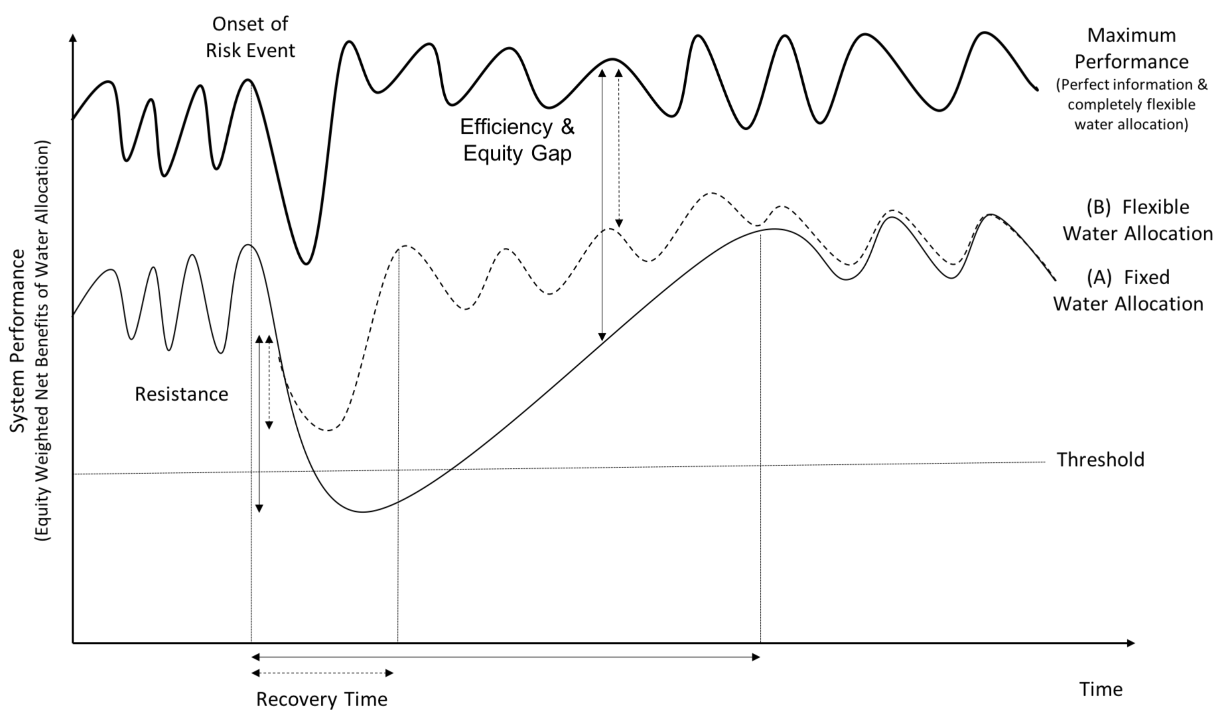

Figure 2.2. Resilience and water reallocation in multipurpose hydropower systems. Adapted from Grafton & Little (2017). The dotted line is the time-path of Scenario B (Flexible Water Allocation).

There are two different scenarios: (A) 'Fixed Water Allocation', where conventional hydropower governance instruments, such as water licenses with fixed operating constraints, provide limited incentives or discretion for hydropower operators to reallocate water across different energy and water services; and (B) 'Flexible Water Allocation', where reforms to governance instruments enable water reallocation as the economic value of and social preferences for different services change. The distance between either scenario and the maximum performance level provides a relative measure of system performance, or the 'efficiency & equity gap'.

There is a sharp reduction in wet season rainfall (henceforth a 'drought') that causes two risk events: (i) reduced reservoir inflows (Risk W1), and (ii) increased demand for and value of irrigation water extractions (Risk W3). The net impact for both Scenarios and the theoretical maximum are sharp falls in system performance because the foregone benefits from major reductions in hydropower generation (due to lower storage levels) outweigh the higher benefits from a given (pre-drought) level of irrigation extractions. The drought also causes shifts in social values: in this case, it is assumed that an increased weighting is placed on farmer profits and the positive externalities from irrigation water services (e.g. food security and rural development) compared to hydropower profits and the positive externalities from energy services (e.g. energy security and climate change mitigation).

The resilience of the multipurpose hydropower system is higher under Scenario B compared to Scenario A. Although performance falls in both cases, resistance is higher in B because the fall in hydropower generation is partially offset by additional water being allocated to irrigation. The recovery time is also shorter in Scenario B because water can be optimally reallocated between water and energy services as the reservoir storage builds again and the imbalance between the weighted value of the different water uses gradually declines. By contrast, system performance under Scenario A only recovers once reservoir storage levels (and hydropower generation) return to pre-drought levels and distributional weightings across irrigation and energy services return to their pre-drought values. Without the capacity to redistribute towards irrigation, the fixed water allocation becomes a misallocation of the (lower) volume of water that is available. Figure 2.4 does not allow us to demonstrate robustness because it depicts a single adverse event. However, if the fall in system performance is always proportional to the reduction in rainfall (i.e. the severity of the drought) and, if resistance is always relatively lower under Scenario A, then it follows that the number of times (and probability) that the threshold will be breached over many droughts would be less under Scenario B.

The simple example above illustrates how the reallocation of water can support the resilience of multipurpose hydropower systems to short-term, water risks. The insights from Figure 2.4 extend to the other water and energy risks defined in Section 2.2. For example, a sharp fall in electricity prices or end of a carbon credit scheme would reduce system performance (due to lower hydropower revenues), but the capacity to efficiently and equitably reallocate water (i.e. until the weighted marginal benefits of all water and energy services are equal) would support system resilience and recovery time. Similarly, the magnitude and duration of performance loss from a long-term adverse risk event, such as a gradual decline in reservoir inflows or marginal hydropower revenues, could be managed via water reallocation; the major difference to the situation depicted in Figure 2.4 would be a flatter slope in the performance decline following the onset of the event. Finally, I have presented a simple, theoretical illustration for rivalrous water extractions where there are direct trade-offs between just two services: electricity generation and irrigation water provision. In practice, system performance could be projected or measured for alternative governance instruments across many rivalrous and complementary services using a combination of valuation tools (to estimate allocative and dynamic efficiency) and participatory tools (to assign distributional weights).

Risk events	Location (Year)	Services	Description	Sources
W1 & W3	Quang Nam Province, Vietnam (2013-2014)	Hydroelectricity, Irrigation water, Urban water	Low inflows caused the Dak Mi 4 reservoir to fall below the threshold level to generate electricity. Severe drought was afflicting downstream farmers and contributing to salinization of the urban water supply of Danang, Vietnam's 4th largest city. Despite the technical capacity to release water through a dam sluice gate, the operator focused on increasing storage to meet electricity contracts. The impasse between local authorities and the operator was only concluded after years of negotiations between national government ministries.	RFA (2013); Le & Lam (2013)
W1 & W3	Orville Dam, United States (2017)	Flood control, Urban water, Irrigation water, Hydroelectricity	Following several days of record rainfall, the primary spillways gates of the Oroville Dam were opened to maintain the safety of the dam wall. Structural failure of the spillway caused operators to reduce the outflow, leading to rising lake levels and flow over the emergency spillway which, in turn, failed structurally, generating rapid erosion and causing evacuation of 180,000 people downstream. An independent review found this major incident was caused by a reactive approach to infrastructure management and an emphasis on water supply and power production over flood control and dam safety.	France et al. (2018)
W1, W3 & W4	Sao Paolo, Brazil (2014-2015)	Urban water, irrigation water, hydropower	A major drought exacerbated long-term stressors (population growth, urbanization, deforestation, water pollution), causing acute water insecurity for this city of 20 million people. By January 2015, main water supply reservoirs held 5% capacity. Severe water rationing occurred, and hydropower production fell by 110 TWh across SE Brazil.	Hunt et al. (2018); Nobre & Marengo (2016)
E1 & E2	Norway (Future)	Hydroelectricity, Renewable energy integration, Fish habitats	Norway's hydropower reservoirs could provide the energy storage needed to completely decarbonise the European Union's electricity system. However, the installation of pumped hydropower facilities could cause rapid fluctuations in reservoir levels and undermine the alpine ecosystems that provide habitats for fish and other aquatic species.	Charmasson et al. (2018); Hirsch et al. (2017)
W1, E2	Tasmania, Australia (2015-2016)	Hydropower, irrigation, environmental flows, recreation	A confluence of water and energy risk events led to a major energy crisis in the island state of Tasmania where hydropower is the predominant electricity source. Since 2005, a privately-owned long-distance cable (Basslink) has enabled electricity exports to and imports from the mainland. The anticipated abolition of a carbon price in 2014 prompted the state-owned hydropower company to export large volumes of electricity while marginal revenues remained high, leading to record profits in 2013-2014. Extremely low rainfall in 2014-2015 prevented storage recovery and the state faced a serious electricity supply deficit when a Basslink fault occurred in late 2015. Major energy users reduced loads and expensive diesel generation capacity was installed. Basslink was offline for 6 months whilst system-wide storage levels fell to 12.5%, or half the standard operating minimum. The cause of the fault was found to be overloading the cable beyond its design capacity in years prior to the crisis.	Hydro Tasmania (2016, 2017); TEST (2016)

Table 2.3. Case studies demonstrating exposure of multipurpose hydropower systems to water and energy risks.

2.4. Reforms for Resilience

There is growing awareness in the hydropower industry of the need for resilience to climate change, extreme weather events, and other adverse risks (e.g. IHA 2018b; Karki et al. 2016; Ray et al. 2018; WEC 2015b). Proponents of multipurpose hydropower reservoirs highlight the capacity for dam infrastructure to increase the resilience of food-energy-environment-water systems more generally (e.g. Rex et al. 2014). In this Chapter, I have shown that this capacity can only be realised if governance instruments can efficiently and equitably reallocate water stored in reservoirs. Under emerging water and energy risks, conventional hydropower governance instruments provide limited incentives for dynamic multipurpose operations. At best, the absence of adaptive governance could mean that opportunities will be missed to generate additional benefits from hydropower infrastructure. At worst, multipurpose reservoirs could be sources of cascading failures that transfer systemic risks across communities, economic sectors, and ecosystems. Rather than sharing benefits, poorly governed multipurpose reservoirs could create instability in the provision of essential services. Table 2.3 highlights contemporary examples of multipurpose reservoir systems where water and energy risks are challenging and, in some cases, overwhelming the capacity of governance institutions.

This section proposes three reforms to existing governance instruments that could increase the resilience of multipurpose hydropower systems to water and energy risks. There are important barriers to water reallocation that encompass sociocultural factors, hydrological and infrastructure constraints, and political economy considerations (see Marston & Cai 2016 and Grafton et al. 2017 for reviews). These barriers include financial costs, third-party effects (or externalities), lack of information, lack of property rights, and vested interests. Table 2.4 summarises the three reform opportunities in terms of (i) the aspect(s) of resilience they address, (ii) the water reallocation barriers they overcome, and (iii) challenges to their implementation. Note that all of these reforms are complements to rather than substitutes for the conventional hydropower governance instruments outlined in Section 2.2.

Reform	Summary	Component(s) of resilience	Water reallocation barriers overcome by reform	Implementations Challenges
Periodic relicensing	Limited license durations (< 30 years) to reassess benefits and costs of operations, identify required infrastructure investments, & renegotiate water allocations. Single, independent regulator. Operators required to demonstrate net social benefits. Participatory decision-making, with public interest taking priority. Stress-testing of alternative climate, energy market, and water demand scenarios. Alignment of licenses within a shared catchment. Applicable to all types of water services (e.g. public, private).	Resistance, Robustness	• Poor/inappropriate definition of property rights • Poor/inappropriate definition of system boundaries • Information asymmetry	• Transaction costs • Limited administrative capacity
Water pricing	Payment by private water users to hydropower operator (directly or via intermediary) for the provision of water services additional to operating constraints defined by water licenses. Two-part tariff including: (i) volumetric water price approximating opportunity cost of water provision (i.e. foregone energy revenues), and, where applicable, (ii) fixed charge reflecting additional cost of infrastructure to provide water services.	Resistance, Recovery time, Robustness	• Vested interests • Financial costs • Unreliable water supply • Inadequate infrastructure	• Social norms • Monitoring & enforcement • Limited administrative capacity
Climate/green performance bonds	Variable-interest bonds conditional on the bond issuer (the hydropower company) meeting specific conditions during operations. Lower rate of interest paid if input- or output-based indicators of water service provision met. Higher rate paid to bond holder if not met, and difference used to compensate intended beneficiaries of water services in cash or programs.	Resistance, Recovery time, Robustness	• Vested interests • Inadequate infrastructure	• Complex policy design • Information limitations • Monitoring & enforcement • Transaction costs

Table 2.4. Summary of proposed governance reforms to enhance the resilience of multipurpose hydropower systems. Water reallocation barriers and implementation challenges adapted from Marston & Cai (2016) and Grafton et al. (2017).

2.4.1. Periodic Relicensing

The end of a hydropower license period is a window of opportunity for water reallocation. Relicensing processes enable regulatory agencies to work with hydropower companies and water users to: (i) reassess the benefits and costs of current and alternative modes of operation, including decommissioning; (ii) identify investments to maintain, upgrade, and modify infrastructure; and, in the case of license renewal, (iii) renegotiate the water allocation embodied in operating conditions and license constraints. Hydrological changes from climate change pose dam safety concerns that will necessitate periodic relicensing of hydropower projects (Pittock and Hartmann 2011). Regular reviews of dam infrastructure and operations for that purpose also present an opportunity to adaptively manage environmental impacts, balance dynamic trade-offs between water and energy services, and identify alternative sources of water services other than hydropower infrastructure (Pittock & Hartmann 2011; Rheinheimer et al. 2013; Viers 2011; Viers & Nover 2018; Watts et al. 2011).

A relicensing regime that increases the resilience of multipurpose hydropower systems may include: (i) a single, independent regulatory agency to license all dams, barriers, and major water infrastructure; (ii) operators needing to demonstrate that infrastructure will generate net social benefits across both water and energy services; (iii) participation of water users and affected stakeholders in decision-making, with the public interest taking priority in the regulators' final decisions on relicensing and future operating conditions; (iv) incorporating climate change projections and 'stress-testing' license conditions across alternative scenarios for the development of social-ecological systems; and, (v) alignment of license periods for all water projects within a catchment to allow collective benefits and costs to be assessed and managed even if projects are owned by different private and public interests (see Pittock & Hartmann 2011 and Viers & Nover (2018) for further description of these and other elements of a periodic hydropower relicensing regime).

Periodic relicensing could increase the resilience of existing hydropower systems in multiple ways. Limited license durations (i.e. less than 30 years) and periodic review of operating constraints could reduce recovery time when slow-onset risks create expanding trade-offs between energy and water services. More frequent revision of operating boundaries would provide opportunities to learn from extreme hydrological events and increase long-term robustness of the system. Where both licensing and financial safeguard regimes are in place, reporting requirements and safeguard frameworks could be integrated into the relicensing process, along with a facility for concessional finance of infrastructure modifications as the need arises. The Hydropower Sustainability Assessment Protocol and other corporate social responsibility instruments could feature as participatory tools in the relicensing process, with assessment results providing benchmarks for performance monitoring (e.g. critical thresholds for system robustness).

In terms of overcoming barriers to water reallocation, updated operating conditions would enable dynamic reassignment of property rights to water and, hence, flexibility to increase allocative efficiency and equity. Participatory assessment under relicensing supports the redefinition of system boundaries to include (exclude) new (old) services. There are significant barriers to hydropower companies obtaining information on the externalities associated with their operations and the dynamic value of water services; structured, regulator-led processes could provide a framework and resources for operators to obtain more and better information.

In practice, a major challenge to periodic relicensing is transaction costs. The 5-7 year FERC relicensing procedure mentioned in Section 2.2 is a multi-stage process involving substantial financial, legal, and human resource costs (Kosnik 2013). More regular reviews could increase the costs of hydropower companies negotiating with stakeholders and the regulator reviewing evidence and making decisions. Furthermore, there are trade-offs between efficient and equitable water reallocation and providing certainty to project investors and financiers on returns from the large, up-front costs of hydropower infrastructure. One avenue to manage this trade-off could be a "no-loss relicensing condition" wherein all parties must agree to license modification if the changes are, on aggregate, estimated to generate net benefits without reducing the welfare of any party (Madani 2011); in practice, however, such potential "win-win" outcomes may not be that common. Alternatively, ranges for operating constraints, such as seasonal minimum flows, could be specified for the long-term (30-50 years) with medium-term reviews (5-10 years) that set specific values across a small number of water license parameters; such periodic reviews are consistent with current practice of the US Army Corps of Engineers – one of the largest operators of dams in the United States – which reviews and updates water reservoir manuals at least every 10 years (Benson 2018). Further, values could be specified for particular water supply and demand variables, such as urban population growth, or indicators of system performance, such as urban water security, that trigger a partial/full relicensing process or a specific change to operating constraints and water supply arrangements.

Key to successful implementation of the proposed components of a relicensing regime is the institutional capacity of the regulatory agency, including: (i) human capital, (ii) financial resources to manage relicensing negotiations, (iii) legislative mandate to monitor outcomes and enforce punishments for non-compliance, and (iv) transparency and accountability to the public interest. Power imbalances between hydropower companies, state utilities, and private users of water can be very significant and need to be managed fairly by an independent regulator. In many countries, institutional capacity is limited. An important step towards a relicensing process is, in the first place, an effectively implemented licensing process that can balance trade-offs between the financial interests of hydropower companies and the welfare of other water users.

2.4.2. Water Pricing

A water price is a charge for accessing and using water that has been processed in some way, such as storage in a reservoir or transmission through an irrigation channel or pipe (Griffin 2015). Pricing is commonly used by utilities and irrigation companies to charge water users for the fixed and variable costs of water provision in both rich and poor countries (see Dinar et al. 2015 and OECD 2010 for case studies). Here, I consider how water pricing could complement existing instruments by enabling reallocation of water outside the boundaries defined by operation constraints. Specifically, I propose a water tariff charged by a hydropower company for services where water is used as a private good, such as irrigation, urban, and industrial water supply. In these cases, water pricing could enable an efficient transfer of water that is prevented by a missing market. The tariff could contain two components: (i) a volumetric price for each unit of water that reflects the opportunity cost of delivering that water (i.e. foregone hydroelectricity revenues), and (ii) a fixed charge that reflects any capital expenditure or other fixed costs (e.g. additional staff) incurred by the hydropower company providing water services beyond those specified in its water or energy license.

The general principles of applying water pricing to hydropower governance can be illustrated through the objectives for water reallocation and specific barriers to that occurring. Allocative efficiency can be improved by enabling water to be transferred to non-energy uses when it is more efficient to do so and, potentially, in a timelier manner than revising operating constraints or renegotiating water licenses. For example, increased benefits may be realised where the marginal value of delivering water to energy production (i.e. when electricity prices are low) is less than transferring it to irrigation (i.e. when irrigated water demand is high) but conventional governance tools, such as fixed water allocations, do not facilitate the transfer. Hydropower operators' charging beneficiaries for the fixed costs of private water service provision enables finance of increased storage capacity or construction of water transmission infrastructure. Further, creating revenue streams from water services could: (i) provide hydropower companies with the discretion to deliver water to those services during droughts when water has a higher value for other water users but there are also significant opportunity costs from foregone hydroelectricity generation, and (ii) remove operators' financial incentive to maximise water allocation to hydropower.

Pricing water could increase the resistance and robustness of multipurpose hydropower systems to adverse risks, whilst reducing recovery time when they occur. Under drought conditions a scarcity-based water price could help reallocate water efficiently (i.e. increasing resistance) and, in the long-term, provide water users with incentives to develop alternatives sources of water services if it is efficient to do so (i.e. increasing robustness). Moreover, the capacity to generate revenue from water supply provides incentives for hydropower operators to maintain a storage buffer: in the case of reduced inflows, excess demand for water services could equate to foregone revenue from water provision. Water tariffs can also signal the optimal timing for new infrastructure investments to increase water storage (Grafton et al. 2014); in the case of hydropower reservoirs, such investments may include raising dam heights or sediment removal to increase system robustness. Finally, water pricing could reduce system recovery time in the presence of energy market risks by enabling opportunities for efficient water reallocation. For example, fast- or slow-onset falls in hydropower revenues will decrease overall system performance, but a falling water price would allow farmers and other users of water services to increase welfare or profits by increasing their water extractions until allocative efficiency is achieved (i.e. until the marginal benefit of additional water equals the volumetric water price).

A key challenge to deploying water pricing for multipurpose hydropower governance is ensuring an equitable outcome. Typically, hydropower companies are large corporations and there may be significant financial and power imbalances with other water users. Notwithstanding that water storage is a legitimate, costly service and both sides can benefit from a transaction that enhances allocative efficiency, any institutional arrangement where less powerful groups, such as subsistence farmers, pay a large, profit-oriented company to access a natural resource may conflict with social norms. On the other hand, equity may be less of a concern if the water user(s) are engaged in commercial activity, such as large-scale irrigation or manufacturing, or water is being delivered to an intermediary with a large customer base, such as an urban water utility. Distributional considerations are context specific and need to account for externalities as well: diverting water from electricity generation may reduce energy access for poor households, while wealthy elites may be the major beneficiaries of enhanced urban water services provision. In any case, there are options to integrate equity considerations into water pricing whilst preserving incentives for efficient water allocation, such as (i) water tariffs including a free initial volume of water, (ii) means-tested reductions in the fixed charge component of water tariffs, and (iii) cash transfers from government authorities or utilities to water users that reflect the reduced total costs of water supply due to those users accessing water from hydropower storage rather than, say, an over-exploited aquifer or a desalination plant.

A further challenge is the institutional capacity required to regulate water pricing arrangements. The pricing schedule would need to be determined by an independent agency such that the volumetric price approximated foregone energy revenues; this is not a straightforward task because it is difficult to specify when a given unit of water would have been used to generate electricity otherwise, nor what the prevailing value of that water would be. Monitoring and enforcement of non-compliance is necessary, as are transparent and accountable regulatory instruments. Both the equity and institutional capacity challenges discussed here reinforce that water pricing would need to occur within an already developed system of water licenses, operating constraints, and, potentially, financial safeguards and corporate social responsibility initiatives.

2.4.3. Climate/Green Performance Bonds

Climate and green bonds constitute a rapidly growing source of finance for investments in climate change mitigation, climate change adaptation, and environment sustainability. As of 2018, the total value of climate and green bonds was estimated to be USD$ 1.45 trillion globally (CBI/HSBC 2018). These financial instruments enable governments, corporations, or banks to issue debt that is purchased by investors (similar to a loan), with a schedule of interest payments, and the original value of the debt repaid upon maturity of the bond at a predetermined date. The difference between green or climate bonds with standard bonds is that all or part of the loan funds projects or outcomes that support environmental sustainability and/or climate change mitigation and adaptation. Investors purchase these bonds to fulfil corporate social responsibility targets and, in some jurisdictions, benefit from preferential tax on income from interest payments. Certification schemes can provide ex ante (i.e. before-the-event) verification of a bonds' expected outcomes and impacts, the most prominent example being the Climate Bond Initiative (CBI) which maintains a list of approved verifiers and methodologies.

The hydropower industry's access to the green and climate bond market has been restricted thus far because of: (i) concerns over methane emissions in tropical reservoirs, and (ii) concerns over the potential negative and social impacts of large hydropower reservoirs (IHA 2018b; Ironside 2015). A Hydropower Technical Working Group under the CBI has been established to specify screening criteria and associated methodologies to "identify and monitor hydropower investments which deliver climate change mitigation benefits and/or incorporate adaptation and resilience impacts" (CBI 2018a). Although green/climate bonds could facilitate investments in multipurpose reservoir infrastructure, the ex ante nature of certification creates major limitations. Similar to conditional safeguards, questionnaires and scorecards to determine the *capacity* for a financed project to deliver water services under risks do not ensure that they will be actually delivered after a bond has been certified and issued.

As of March 2019, the criteria for hydropower certification have not been finalised and published under the CBI, but the water infrastructure criteria provide useful insights into their potential structure (CBI 2018b). There is a climate change mitigation component and an adaptation and resilience component. The latter requires the bond issuer to undertake a vulnerability assessment and prepare an adaptation plan if the funded asset or project has an expected lifetime over 20 years. The verifier evaluates the assessment using 89 questions across four categories (allocation, governance, diagnostics, and nature-based solutions) and the plan across 6 questions. If the total score is more than 60% for all categories, then the bond is certified. Screening processes like these are undoubtedly valuable and, applied to hydropower, could generate important information and promote behavioral change on the part of the bond issuer. But they would not provide tangible incentives to reallocate water efficiently and equitably during operations: reporting is voluntary and compliance and enforcement measures are absent. Following CBI certification, bond issuers are required to prepare reports, but verification is not required and there is no process for decertification or any other compliance mechanism. Hence, there would be no punishment for a hydropower company issuing a bond for, say, a multipurpose project supporting urban water security, and theb not operating the reservoir to deliver that outcome during a drought or if water demand changed. Further, investors in these bonds would not be assured that the actual outcomes of their investment will generate planned outcomes.

In order to address these compliance challenges and facilitate the use of climate and green bonds to finance multipurpose projects, I propose a specific class of climate and green bonds for application to hydropower reservoirs. The instrument could provide finance to both new and existing projects through a variable interest bond that is conditional on the delivery of water services. An indicator is defined for a specific level of performance with regards to climate change adaptation or environmental sustainability; the indicator could be input-based (e.g. volume of water delivered to farmers) or outcome-based (e.g. farmers' water security). If the condition is met within an interval between interest payments (e.g. a 6- or 12-month period), then the payment is subject to a low interest rate. If the condition is not met, the hydropower company pays interest at a higher rate and the investor transfers the difference to the beneficiaries of water services via an established intermediary (e.g. local government or civil society organisation) as a direct cash transfer (e.g. emergency assistance during drought) or program funds (e.g. supporting drought management programs). Rather than a binary high- or low-rate, a schedule of interest rates could incentivise progressively improved performance (e.g. moving to a lower schedule on a multi-level scale for every successive interval when conditions are not met). This framework combines elements of four different types of financial instruments: (i) climate/green bonds; (ii) performance bonds that are commonly used in the construction industry to penalise the failure of contractors to meet scheduled targets, (iii) index-based weather insurance and climate derivatives (Denaro et al. 2017; Foster et al. 2015; GCube 2015; World Bank 2013a), and (iv) social impact bonds that provide outcome-based payments (Gustafsson-Wright et al. 2018).

The framework of conditions and incentives would be suitable for all hydropower projects regardless of whether multipurpose operations are an explicit objective and, indeed, for any infrastructure investment where the outcomes are a result of how it is operated (e.g. drip-irrigation technology) and not the existence of the infrastructure in and of itself (e.g. a dyke to protect against sea-level rise). The objectives of climate/green performances bonds are three-fold: (i) provide hydropower companies with both finance and a financial incentive to deliver water services and support the resilience of multipurpose hydropower systems (including all water users); (ii) in the event that specific indicators or outcomes are not met through the company's actions, provide financial resources to support the economic sectors and water users adversely affected by water security risks and/or the failure to reallocate water; and (iii) assure investors that they are funding the resilience of water users within the multipurpose reservoir system to climate change (in the case of a climate bond) and/or the environment sustainability of hydropower operations under both energy and water risks (in the case of a green bond).

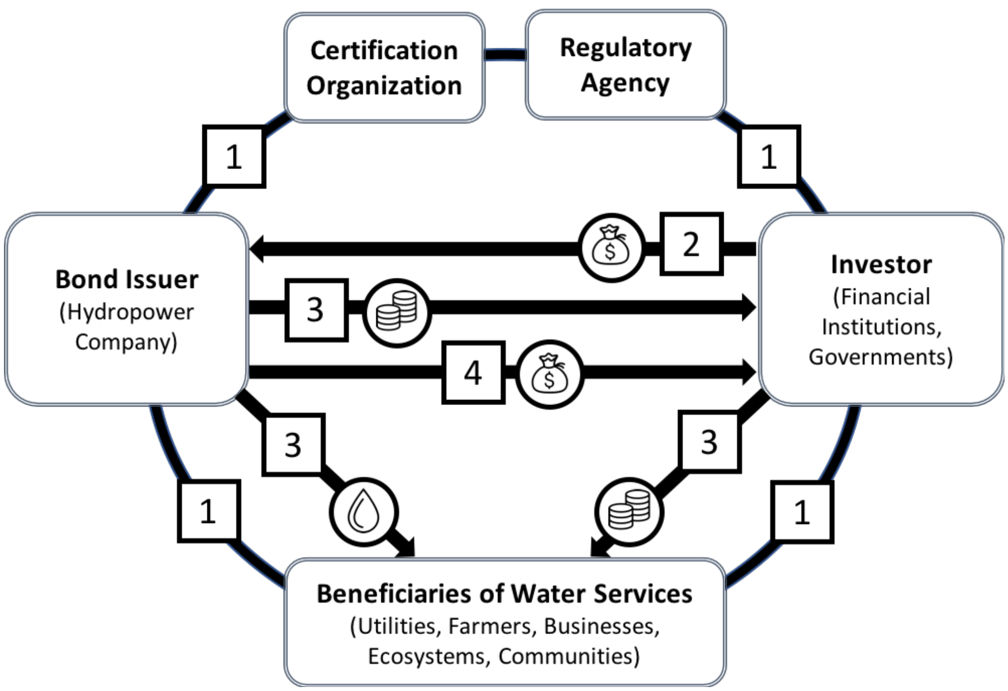

Figure 2.3. Framework of a climate/green performance bond.

Figure 2.3 illustrates the process:

1) The bond issuer cooperates with a financial institution to design the bond, with the parameters of the agreement being developed through consultation with other stakeholders (e.g. beneficiaries of water services, regulatory agencies, certification organisation);

2) The investor transfers the principal to the bond issuer – the face value of the bond that will be returned to the bond issuer upon maturity of the bond;

3) The hydropower company invests in the assets or project that the bond is designed to fund. If the provision of water services meets performance conditions, the hydropower company pays interest to the investor at a lower rate. If performance conditions are not met, the hydropower company pays interest to the investor at a higher rate. In the latter case, the investor transfers the additional interest repayment to the intended beneficiaries of water services via direct payments (e.g. cash transfers) or through programs delivered by existing local organisations;

4) The bond matures and the hydropower company pays back the principal to the investor.

Climate/green performance bonds could potentially be sold by the initial investor in a secondary market. For example, a financial institution familiar with the climate/green bond market could on-sell bonds to corporations, government entities, or individuals seeking to invest in climate change adaptation or environmental sustainability. In the case that a government entity was a primary or secondary investor, this arrangement could supplement regulations intended to support provision of water services and provide a source of finance to ameliorate negative impacts from hydropower operations not delivering performance targets.

Performance bonds are a means to support system resistance and robustness, as well as overcome various barriers to water reallocation. In the event of a short-term adverse risk, such as a drought, the hydropower companies have an incentive to maintain water services delivery or provide additional resources to offset adverse impacts on other water users. Further, key thresholds for system performance can be explicitly built into contract design, thereby supporting system robustness. Performance bonds could provide incentives to shorten system recovery time after a minimum threshold was breached, but that would depend on contract design (e.g. interest payment intervals). In terms of water reallocation, these bonds support investment in infrastructure that can deliver multipurpose operations as well as the efficient and equitable use of that infrastucture. Financial incentives for hydropower companies to deliver water services could help overcome the vested interest in maintaining minimum deliveries or, in other words, create an opportunity cost for not delivering external benefits when their value is high. While this instrument could support the delivery of private goods, it could be most useful in the context of public goods or common-pool resources, particularly where a government organisation is the investor.

The major challenges to implementing climate/green performance bonds is that they would require input from a range of stakeholders in the design of the contract and the broader program. These transaction costs could be offset, however, by connecting their design to other regulatory processes, such as (re)licensing procedures, and building on the information and stakeholder relationships developed therein. The design of these bonds would be complex and require detailed analysis at the beginning to ensure that the appropriate incentives were in place. If outcome-based indicators were used to assess performance (e.g. household water security), then monitoring and evaluation costs could be high.

2.5. Conclusion

This Chapter argues that multipurpose hydropower development requires more than planning and intentions. Hydropower companies need defined incentives to efficiently and equitably reallocate water as the net benefits of energy and water services change. The resilience of a hydropower project is the resilience of the encompassing social-ecological system; this important system characteristic is one that can be defined and its components (resistance, recovery time, robustness) supported by dedicated measures. Here, I propose three governance reforms that provide a dynamic regulatory framework to manage emerging water and energy risks. Across all of these proposals and, indeed, conventional regulatory arrangements there is a common need for strong institutional capacity and a portfolio of governance instruments. This commonality emphasises that these proposals are complementary to existing instruments and require their foundation for implementation.

Whether and how particular reforms could be implemented will depend on the jurisdiction and the stakeholders involved. In any case, the following actions would inform their development for any given context and provide insights for broader application:

(i) Measure and project water supply and demand to inform valuation of water services and governance reforms (Garrick et al. 2017);

(ii) Conduct hydro-economic modelling of specific reforms or alternative parameter settings to provide insights into the relative benefits and costs of altering status quo instruments, particularly under alternative scenarios for water and energy risks;

(iii) Use participatory processes (e.g. Reed 2008; Wyrwoll et al. 2018) to integrate equity considerations into decision-making and identify externalities;

(iv) Conduct real-world pilots, particularly in the case of water pricing and climate/green performance bonds where broader institutional reforms may not be necessary.

Chapter 3

Decision-Making for Systemic Water Risks: Insights from a Participatory Risk Assessment Process in Vietnam

3.1. Introduction

Recent attention to the interdependencies between food, energy, environment, and water systems has prompted calls for their coordinated management across levels and scales of governance (Hoff 2011). Here, we evaluate the development of national policy responses to systemic water risks. Systemic risks transfer instability and shocks across network linkages and can cause major failures in affected systems. Water systems are important vulnerabilities because they can transfer instability across food production, energy generation, ecosystem health, economic development, and social well-being.

Advances in the research and practice of risk, water, and natural resources management provide tools to analyse systemic water risks and inform cross-sectoral planning, including causal risk assessment (Fenton & Neil 2012), water resources systems analysis (Brown et al. 2015), and participatory approaches (von Korff et al. 2012). As yet, there is only limited understanding about how to combine different knowledge types and different tools to support decision-making under extreme uncertainty (Döll & Romero-Lankao 2017; Hale et al. 2015), and also an unmet need for physical science and economic research on water resources to better integrate social dynamics and, hence, provide a useful basis for real-world decisions (Loucks 2017).

A key challenge to better decision-making on systemic risks is that uncertainty and complexity undermine the utility of conventional analytical techniques (van Asselt & Renn 2011). National-level risk studies often replicate the limitations of sub-national or private sector assessments, such as the use of two-dimensional risk matrices that do not incorporate uncertainty (Aven & Cox 2016). Although frameworks have been developed and applied for systemic risk management (IRGC 2012; Renn & Walker 2008) and a small number of countries conduct national risk assessments (e.g. Cabinet Office 2015; National Institute for Public Health and the Environment 2014), we are not aware of any cases where systemic risk analysis has guided national policy on food-energy-environment-water systems. Systemic risks are particularly acute for water security and they require adaptive management across the multi-level and multi-scale networks characteristic of water governance (Pahl-Wostl 2016). While our focus in this paper is on water, our approach can be extended to risks emerging from food, energy, or ecosystems. While systemic risks are often regarded in the context of global networks and shocks (Goldin & Vogel 2010; Helbing 2013) and supranational management of transboundary water resources is one important consideration, our analysis focuses on the incorporation of sub-national governance dynamics into national level decision-making.

Our paper is structured as follows. Section 3.2 defines systemic water risks and outlines the dynamics of multi-level and multi-scale water governance networks. Section 3.3 presents a causal risk modeling and participatory approach for systemic risk management. Section 3.4 shows how a process based on this approach was piloted in an applied research project in Vietnam and describes the underlying water governance context. Section 3.5 draws on the results of that project to provide general insights on how researchers can facilitate the integration of sub-national dynamics into national-level policy on systemic water risks. Section 3.6 concludes.

3.2. Management and Governance of Water Risks Within Complex Food-Energy-Environment-Water Systems

3.2.1. Systemic Water Risks

Failures across linked systems can be catastrophic: abrupt climate variability and change, for example, have led to social and political crises throughout history via droughts, food shortages and conflicts (Haug et al. 2003; Parker 2013). Globalisation and human activity are causing systemic risks to emerge that can transfer instability across large distances and cause failure in the key systems and infrastructure on which societies depend (OECD 2003; World Economic Forum 2015). The policy challenge is that systemic risks are dynamic and non-linear; they evade top-down control and generate surprising behavior in affected systems (Helbing 2013).

Systemic risks arise from the complex dynamical systems in which they operate. Key characteristics of these systems include: diversity in system components; dynamic structures in which those components interact; interdependencies that vary in strength, directedness, and time-scale; and the components of the system adapting, learning, and self-organising (Page 2015). The aggregation of non-linear interactions between individuals, organisations, ecosystems, physical infrastructure, and other system components leads to macro-level phenomena that, in turn, affect the subsequent interactions of these components (Levin 2002; Page 2015). Abrupt changes in the dynamics of complex systems can be induced by random noise, endogenous trends within the system, and/or external forces pushing system components beyond 'tipping points' and into alternative states (Helbing 2010; Lenton 2013). Such shifts can lead to cascading failures or, in some cases, greater resilience and system stability (Biggs et al. 2012). Feedback loops connecting system components may either amplify (i.e. positive feedback) or dampen (i.e. negative feedbacks) shocks (Liu et al. 2007).

The financial crisis and food-energy price spikes of 2007-08 demonstrated how quickly systemic risks can generate economic and social crises in the modern, inter-connected world (Bizikova et al. 2013; Goldin & Vogel 2010). Discourse across policy, practice, and research has subsequently emphasised the management of connected systems which underpin human societies and ecosystems (Centeno et al. 2015; Oppenheimer et al. 2014; World Bank 2013; World Economic Forum 2015). Central elements include: (1) the linkages, or 'nexus', between food, water, energy, and other connected systems (see Weitz et al. 2017 and Wichelns 2017 for recent reviews); and (2) the 'resilience' of social, ecological, governance, and infrastructure systems to environmental and man-made shocks (Hallegatte et al. 2017; OECD 2014; World Energy Council 2015), where resilience is, typically, defined as the capacity of systems to adsorb and adapt to shocks, re-organise their components, and subsequently grow and thrive beyond the pre-shock level of system performance (see Holling 1973; Levin et al. 1996; Walker et al. 2004; Folke et al. 2010).

The burgeoning attention towards 'the nexus' and resilience has highlighted key issues regarding food-energy-environment-water systems. Strong interdependencies can exist between and within these systems (Hoff 2011; Ringler et al. 2013; Scanlon et al. 2017). Trade-offs exist: increased water allocation to one sector, for example, can cause networked shocks by reducing water availability for others (Zeng et al. 2017). Global population and consumption trends are undermining food-energy-environment-water systems and are a key cause of social conflict and political crises (Beddington 2009). Feedback effects can, and do, occur while short-sighted policy and management decisions can produce unintended, perverse consequences (Hussey & Pittock 2012; Pfeiffer & Lin 2014). Framing and addressing major, systemic instabilities must also account for institutions (Weitz et al. 2017) and the agency of people and communities at the local level (Allouche et al. 2015). In sum, the systems associated with food, water, energy, and the environment comprise a complex system that generates systemic risks.

Water resources and water infrastructure are key nodes and pathways for the transfer of instabilities across food, energy, and environmental systems. Low water availability, for instance, is a key risk to both hydropower and thermal energy generation, with higher water temperatures due to climate change further undermining the efficiency of thermal plants (Rodriguez et al. 2013; van Vliet et al. 2016). Global agricultural trade can generate networked shocks by disseminating the impacts of water scarcity across countries (Tamea et al. 2016). Non-point source water pollution embodies the management challenge posed by dynamic, uncertain interactions occurring at the micro-scale (Patterson et al. 2013), but is also caused by global patterns of food demand and agricultural trade (Xie & Ringler 2017).

Water security has been defined as the "the capacity of a population to safeguard sustainable access to adequate quantities of and acceptable quality water for sustaining livelihoods, human well-being, and socio-economic development, for ensuring protection against water-borne pollution and water-related disasters, and for preserving ecosystems in a climate of peace and political stability" (UN-Water 2013). Water insecurity is a key conflict multiplier in fragile states (Sadoff et al. 2017) and an increasingly important driver of migration (Miletto et al. 2017). Rural women in developing countries are disproportionally affected by water insecurity and their limited resources for adaptation can lead to further disempowerment (Parker et al. 2016).

The systemic risks associated with water resources are increasingly recognised (Pahl-Wostl 2016; World Economic Forum 2015). Adapting the typology of OECD (2013) and drawing on the UN-Water (2013) definition of water security, we propose four sets of 'systemic water risks', or events where water resources and their management transfer shocks and cause failures across connected systems: (1) water demand exceeds the supply needed to meet particular objectives over a specific time period; (2) inadequate water quality for a specific purpose, such as provision of drinking water; (3) excess water that prevents objectives being met or imposes costs, such as flood events; and (4) the loss of a key freshwater ecosystem function or component, such as a wetland. Table 3.1 describes elements of systemic instability that food-energy-environment-water systems can exhibit, with specific examples from water resources management.

Element	Description	Example from water resources management
Threshold effects	Unexpected transition or systemic shifts	Freshwater eutrophication
Randomness in a strongly coupled system	Mean approximations provide inaccurate forecasts of system behavior; strong correlations between performance of linked systems	Unpredictable hydrological variability
Positive feedback	Dynamic instability and amplification effect, equilibrium or stationary state cannot be maintained	Policies for water-use efficient irrigation infrastructure causing a 'rebound effect' in water consumption and reducing return flows to ecosystems
Wrong timing (mismatch of adjustment processes)	Over-reaction, growing oscillations, or loss of synchronisation	The disruption of downstream environmental flows by hydropower operations
Strong interaction, contagion	Cascade effects	Droughts in hydropower-dominated energy sectors causing blackouts & impacting groundwater extraction for irrigation
Complex structure	Perturbations in one network affect another one	Deforestation for food production causing soil erosion and reduced runoff that negatively impact aquatic ecosystems
Complex dynamics	Self-organised dynamics, emergence of new systemic properties	Aggregation of total water demand across many water users
Complex function	Sensitivity, opaqueness, scientific unknowns	Uncertain origins of non-point source water pollution
Complex control	Time for computational solution explodes with system size; delayed or non-optimal solutions	The economic value of water across different uses varying across time, geography, and scale
Optimisation	Orientation at state of high performance; loss of reserves or redundancies	Exposure of multiple agricultural supply chains to water insecurity disruptions in one location
Competition	Incompatible preferences or goals	Rivalrous water consumption under limited supply
Innovation	Introduction of new system components, designs or properties; structural instability	Ongoing water reform processes; disruptive technologies, such as solar water pumps

Table 3.1. Elements of systemic instability in food-water-energy-environment systems originating from water resources and/or their management. Adapted from (Helbing 2013).

3.2.2. Multi-Level and Multi-Scale Governance Networks

Research and practice of managing systemic risks and enhancing resilience provide a range of principles for food-energy-environment-water systems (Biggs et al. 2012; Goldin & Mariathasan 2014; Helbing 2013). They include: (i) preparing for shocks and system failures through measurement, analysis, and experimentation; (ii) maintaining or developing system diversity and sub-component redundancy; (iii) broadening participation in management decisions; (iv) limiting system size to establish an upper bound on disasters; (v) incorporating frictional mechanisms to produce a manageable state when unpredictable instability occurs; (vi) focusing management actions on variables that strongly influence the entire system and the feedback effects that cause nonlinear changes or regime shifts; and (vii) reducing connectivity across networks to prevent contagion if one component fails.

These management principles require decentralisation, flexibility, and patterns of information exchange that are inconsistent with top-down governance. But they also require system-wide knowledge and coordination to understand and influence micro-level dynamics. In practice, water governance regimes in a given country encompass multiple levels of government (Daniell et al. 2014; Moss & Newig, 2010). We distinguish national-level systemic water risks as having sufficient scope to severely impact the social and economic institutions underpinning a nation state. Equally, we could conceive of ‘local-level’, ‘global-level’, or ‘transboundary’ systemic water risks corresponding with the geographic scale of impact and governance. Importantly, water governance is more than just government: it involves the structures and processes through which both public and private actors interact to regulate the development and management of water resources (OECD 2011; Pahl-Wostl 2009). Governance regimes are networks with multiple scales ordered across different levels, including: the administrative scale of government and the ministries, departments and agencies at different levels; the institutional scale for rules governing social and economic interactions; the management scale of strategies, programs, and projects; and private stakeholders and decision-makers (Daniell & Barreteau 2014).

Figure 3.1a. illustrates examples of the interactions that can occur across water governance networks through the material/non-material flows and costs/benefits imposed on a particular level/scale by decisions at another level/scale (Cash et al. 2006; Daniell & Barreteau 2014). The national government provides funding and policy directions to the provincial level of administration. Local agencies provide information to provincial agencies regarding the status of local water resources. Large industrial water users pay a pollution charge to provincial authorities. Water extraction by upstream farming households decreases inflows to a water supply company’s reservoir. Thus, a new strategy to increase irrigation water efficiency requires a change to laws and, in turn, results in new supporting regulations and programs, such as drip irrigation subsidies. Projects implemented at the local level provide knowledge on how programs should be restructured to achieve the objectives of strategies.

The actions of and interactions between decision-makers at all levels/scales aggregate into macro-level phenomena that describe the state or performance of a water system at the national level. Figure 3.1b. provides a stylised representation of this aggregation and its implications:

(i) In period *t*, actions, decisions and interactions occur within the water governance network of a food-energy-environment-water system, such as farmers increasing groundwater extractions or a new law to reduce water pollution being implemented through sub-national programs. Consequently, macro-level phenomena emerge during period *t*, such as water insecurity or increased resilience of the food-energy-environment-water system.

(ii) The decisions, actions, and interactions during period *t* generate dynamics within governance networks that cause feedback effects in period *t+1*. In the case of drip irrigation subsidies, farmers might be encouraged to extend their land under cultivation and planting perennial crops, thereby increasing overall water consumption. For the water pollution law and programs example, industrial water users may invest in pollution mitigation technologies rather than pay fines.

(iii) The macro-level phenomena generated during period *t* have an impact on governance actions, decisions, and interactions within period *t+1*. For example, water insecurity at time *t* may cause rural populations to migrate to other locations where water is less scarce, or prompt local government agencies to re-purpose existing finances to provide emergency loans for struggling farmers.

(iv) Governance actions, decisions and interactions aggregate once again, and new macro-level phenomena emerges in period *t+1*.

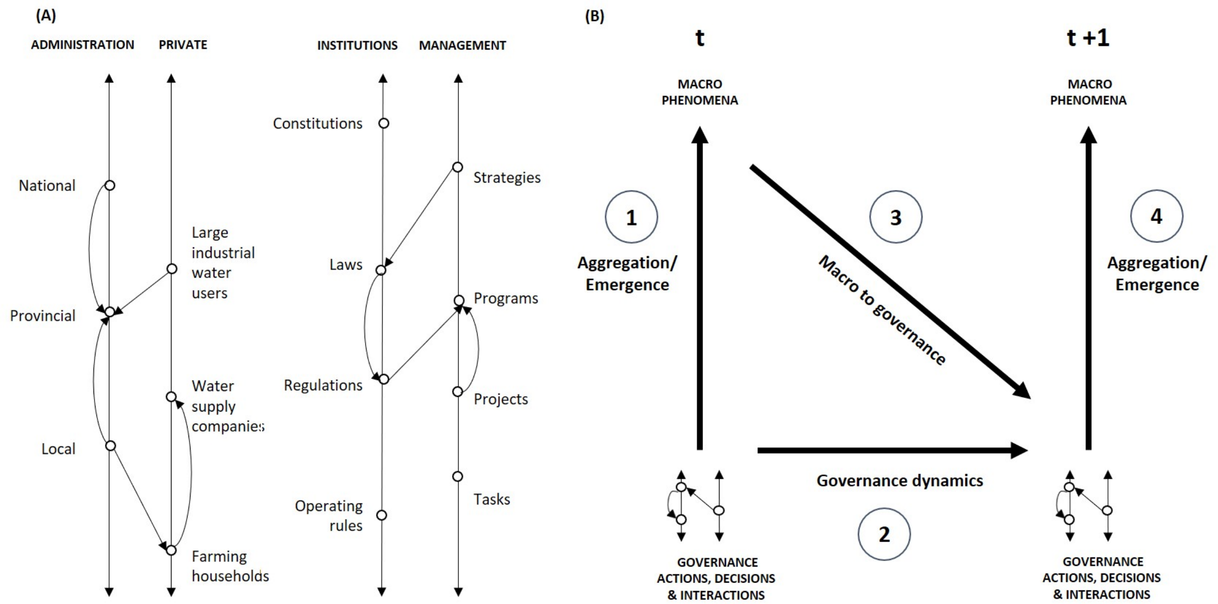

Figure 3.1. Emergent phenomena in complex food-energy-environment-water systems from interactions within water governance networks. Figure 3.1a. (left): Examples of interactions between different level and scales of water governance. Adapted from Cash et al. (2006), Daniell & Barreteau (2014). Figure 3.1b. (right): The aggregation of governance actions and interactions into macro-level phenomena and feedback effects on the next time period. Adapted from Page (2015). See main text for further description of both figures.

In the context of systemic risk management, planning for and attempting to understand the dynamic actions and interactions across governance networks is critical to resilient decision-making. The history of water and land resources management is replete with examples of short-sighted national policy decisions that caused feedbacks and undermined resilience. Examples include: biofuel production subsidies driving up food and energy prices (Mitchell 2008); flood levee construction and land re-zoning leading to urban settlement in floodplains and reduced perceptions of large-scale flood risks (Ludy & Kondolf 2012); and infrastructure-based incentives to recover water for the environment causing reduced return flows and less flexibility of farm production systems (Adamson & Loch 2014; Qureshi et al. 2011). Inaccurate mental models of natural resource systems and their governance networks have often guided the development of top-down policy prescriptions that end in failure (Ostrom & Janssen 2004; Ostrom et al. 2007). In water resources, new management concepts may snowball in popularity through the practitioner and research communities, such that the latest 'solutions' are applied inappropriately (Molle 2008).

An array of policy prescriptions are gaining traction globally for addressing systemic water risks, including: technology-based increases in irrigation water-use efficiency (World Economic Forum Water Initiative 2011), public-private partnerships in irrigation infrastructure (Mandri-Perrott & Bisbey 2016), multi-purpose operation of hydropower reservoirs (Branche 2015), and the establishment of markets to allocate water (Grafton et al. 2016). Although these approaches may have been successful in certain contexts, positive translations and outcomes are not guaranteed in new ones (Keulertz et al. 2016). Water governance networks respond in dynamic and often unexpected ways to national policy interventions. Any policy approach requires an array of supporting actions; water markets, for example, are unlikely to produce efficient water allocation without well-resourced, accountable institutions for monitoring and compliance. Rather than prescriptive solutions to systemic water risks, portfolios of policy options need to be evaluated and tested across the dynamics of complex food-energy-environment-water systems and their governance networks.

3.3. Methods

3.3.1. Causal Risk Modeling

Conventional approaches to risk assessment and management are, in general, inappropriate for systemic risks (van Asselt & Renn 2011). The often-used "risk equals probability times consequence" approach, for example, often conflates very high likelihood-insignificant consequence events with extremely rare-catastrophic events and does not provides the information nor framework for thinking through causation and the effects of management actions (Grafton & Little 2017). Further, the multiple consequences from a risk event are inadequately represented by a single point in a matrix and uncertainty is rarely incorporated (Aven & Cox 2016). To inform better decision-making, an understanding of causality and the uncertainties of costs and benefits of risk management options is needed, based on how individuals, groups, and other system components will respond to risks and policies (Paté-Cornell & Cox 2014).

There are many valid definitions of risk and approaches to risk management (see Aven et al., (2015) for a review). We consider an event-based, causal approach as appropriate for analysing and addressing systemic water risks. Causal models can estimate cause-effect pathways and the strength of interdependencies through quantitative tools, such as Bayesian analysis (Fenton & Neil 2012), and graphical modeling tools, e.g. causal loop diagrams and decision trees (Pearl 2000).

3.3.2. Participatory Risk Assessment

Inputs from technical specialists, decision-makers, and stakeholders are, typically, needed to fully understand and manage a systemic water risk. Major technical advances have occurred in modeling the physical and economic aspects of water systems, but a critical weakness remains: the inability to dynamically represent water management decisions (Brown et al. 2015). Moreover, too often water resources modeling is not conducted and communicated in a manner that supports real decision-making (Reed & Kasprzyk 2009). Overlaying this need are the increasingly complex interconnections between water risks and social systems. As a result, technical experts need to work with stakeholders on developing conceptual models of risks, defining objectives, and understanding how decision-makers across water governance networks respond to policy interventions (Loucks 2017). To mitigate this challenge, participatory and collaborative modeling approaches have been developed and successfully applied to inform water resources planning under uncertainty (e.g. Kwakkel et al. 2016; Palmer et al. 2013; Werick & Whipple 1994). These approaches include: the incorporation of expert judgement where quantitative data is scarce (e.g. Hall et al. 2005), challenging and reconstructing decision-makers' underlying heuristics (e.g. Smajgl et al. 2015), and evaluating the robustness of management options across multiple scenarios (e.g. Groves et al. 2017).

Under uncertainty and complexity, scientific analysis by technical specialists is frequently better placed to inform decision-making if it incorporates stakeholder and decision-maker knowledge. Equally, participatory planning approaches to risk management benefit from the integration of specialist knowledge and scientific modeling. Methodologies for and applications of participatory processes to the management of water and other natural resources (see Voinov et al. (2016) and von Korff et al. (2012) for reviews), typically involve interactive workshops where stakeholders and decision-makers interact in structured discussions concerning an objective, such as formulating a resource management plan. Their benefits can include greater acceptance of decisions by stakeholders (von Korff et al. 2012) and enabling adaptive management (Folke et al. 2005). But there are also challenges: power imbalances between participants can lead to artificial consensus (Few et al. 2007), skilled facilitation is necessary (Reed 2008), and appropriate participants need to be engaged (Glicken 2000).

In the context of systemic water risks, a key challenge for participatory processes is complexity. The practical knowledge and experience of decision-makers and stakeholders may be insufficient to delineate and identify causal pathways between complex physical, economic, and social systems (Reed 2008). Individuals and groups generally rely on beliefs, values, and heuristics to process information (Glynn et al. 2017), and they do not always make rational decisions under uncertainty (Kahneman & Tversky 1979). The heterogeneous distributional impacts of risks mean that different stakeholders will view outcomes differently (Hallegatte & Rentschler 2015). Sharing technical knowledge through skilled facilitation can enable a better understanding of scientific principles and an awareness of external shocks and system components that are beyond stakeholders' and decision-makers' direct experience.

Scientific modeling and participatory processes can be viewed as different ends of a spectrum of risk assessment tools and knowledge. The key point is that they need to be blended through participatory modeling, foresight workshops, and other methods where both decision-makers and researchers are active participants in the risk assessment process. How this blending occurs and when either should be emphasised depends on data availability, the management context, and objectives. Importantly, this mixed methods approach to risk assessment and management addresses the need for adaptive processes of social learning (see Folke et al. 2005 & Pahl-Wostl 2009) that, ideally, lead to actual decision-making and/or inform it in a useful way.

3.3.3. The Risks and Options Assessment for Decision-Making (ROAD) Process

Advances in risk and decision analysis have resulted in causal approaches to risk-based decision-making (e.g. Fenton & Neil 2012). Frameworks have been developed for managing risks from a systems governance perspective (e.g. International Risk Governance Council 2012), conceptualising interactions between food-energy-environment-water systems (e.g. Bizikova 2013; Smajgl et al. 2016), and analysing the dynamics of social-ecological systems (e.g. Ostrom 2009). Here, we briefly review a tool whose design draws on those and other developments in the analysis of risks and social-ecological systems: the Risks and Options Assessment for Decision-making (ROAD) process (Grafton et al. 2016).

The ROAD process provides decision-makers with a tool to understand and manage risks that affect the resilience of food-energy-environment-water systems. It is designed to be flexible, compatible with other risk assessment and decision-making tools, and adaptable across different institutional contexts. A primary function is to enable decision-makers to identify connections across systems and to develop a portfolio of complementary options to address those causal linkages. The ROAD process is updated to reflect lessons from real-world applications, and a guide and project case studies can be found at the website of the Food Energy Environment Water (FE2W) Network (http://www.fe2wnetwork.org).

While ROAD can be adapted for independent use by decision-makers, trained facilitators play an important role in collating knowledge, designing a tailored process, facilitating participatory workshops, and other aspects of application.

The causal, event-based approach to risk in the ROAD process delineates the components of risk and management options into the following elements:

Risk event: an event with uncertain consequences;

Trigger: an event that is the immediate cause of a risk event;

Driver: a threat, trend or other risk source causing a trigger to occur;

Consequence: outcome of a risk event affecting objectives;

Control: an action that modifies the likelihood or the consequences of a driver or trigger causing a risk;

Mitigant: an action that alleviates the after-the-event consequences of a risk;

Likelihood: An estimate of the chance that an event will occur. Can be expressed quantitatively (as a defined probability between 0 and 1), or as a probability interval (e.g. Very Low, Low, Medium...), or qualitatively.

A key intermediate step in the ROAD process is the definition and iteration of a causal risk model using stakeholder and technical knowledge. This graphical tool provides a foundation for assessing risk management options and evaluating the outcomes of decisions (see Food Energy Environment Water Network (2017) for subsequent steps and stages in the process). Figure 3.2 presents a hypothetical causal risk diagram for systemic water insecurity. Water is used to generate energy, produce crops, and support wetland ecosystem. Electricity is sourced from local hydropower generation and electricity imported through a long-distance transmission cable. Agricultural production is increasingly focused on a crop that fetches high prices relative to alternative crops.

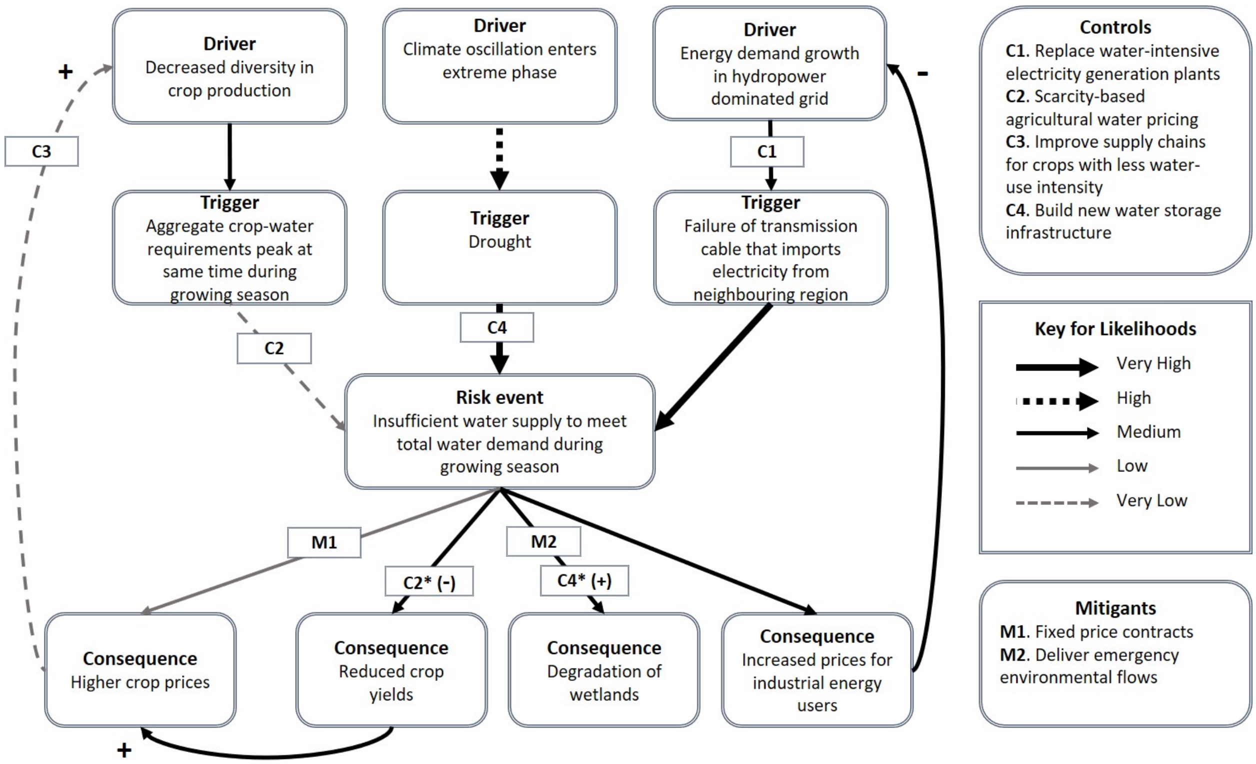

Figure 3.2. Hypothetical causal model of a systemic water risk. Straight arrows indicate cause-effect relationships. Curved arrows indicate feedback effects, with the signs indicating amplifying feedback (+) and dampening feedback (-). The cause-effect linkages targeted by specific controls and mitigants are indicated (e.g. C1, M1), as are their secondary impacts (e.g. C2*(-), C4*(+)). The negative sign qualifying C2* indicates that scarcity-based water pricing dampens the level or reduce the likelihood of crop yield losses. The positive sign qualifying C4* indicates that building new water storage will increase the degree or likelihood of wetland degradation.

The risk event in Figure 3.2 of excess water demand during the growing season is caused by three triggers: (1) water withdrawals across all farmers peaking at the same time as the primary crop reaches maturity (when watering requirements are highest); (2) a drought; and (3) failure of the transmission cable. Trigger 1 is caused by the trend towards less diversity in crop production; Trigger 2 is caused by the shift to an extreme phase in a climate oscillation that strongly affects weather; Trigger 3 is caused by electricity demand growing beyond the capacity of local hydropower generation, leading to an increased reliance on imported electricity. The risk event leads to three consequences that generate possible feedback effects: higher crop prices further encourage mono-cropping, reduced crop yields drive crop prices higher, and higher electricity prices encourage industrial users to improve energy efficiency and develop off-grid generation.

A range of options address specific causal linkages and two of them are considered likely to generate secondary impacts (or feedback effects); in addition to controlling the level of peak water demand, scarcity-based agricultural water pricing is also expected to reduce the level of crop yield reductions if farmers become more efficient in their water use. One option, new water storage infrastructure, is expected to amplify the degradation of wetlands. The directed arrows in Figure 3.2 indicate causal pathways between model components and the arrow types estimate the strength of the cause-effect relationship, e.g. there is a high likelihood that the climate oscillation phase transition could cause drought.

Real-world participatory process could progressively build the causal model by: (1) sequentially identifying the risk, triggers, drivers, and consequences; (2) identifying feedback effects; (3) estimating likelihoods; (4) developing options; and (5) identifying secondary impacts associated with options. This hypothetical, qualitative example does not need to assume time consistency between triggers and consequences; in practice, this may be necessary to inform quantitative modeling of options. Both the risk event and consequences are value-neutral in recognition of the different perceptions and outcomes for stakeholders.

3.4. Application

This section outlines the context and application of an applied research project conducted in Don Duong District of Lam Dong Province, Vietnam. The project began at the end of the record-breaking 2015-2016 drought in Vietnam that provided impetus for the national government to accelerate a reform agenda for agricultural water management. The project site is the location for a planned pilot of new water management policies by national and provincial government agencies. The risk assessment activities undertaken in the research project were an input to the design of the policy pilot.

3.4.1. Case study: Piloting Water Management Reforms in Don Duong District of Lam Dong Province, Vietnam.

3.4.1.1. Systemic Water Risks in Vietnam

Vietnam is highly exposed to systemic water risks of national significance. Population growth and economic development are driving rapid increases in water demand across all sectors; total water consumption is projected to almost double between 2013 and 2030 (ADB 2013a). On the supply-side, severe drought and saline intrusion have caused major crop losses and reduced household water access across key food production and population centers of Vietnam (United Nations Disaster Risk Management Team 2015). Flooding and storms are an ever-present threat for any coastal country with a monsoonal climate, but Vietnam's long coast line, mountainous geography, and large deltas render households, farming systems, and physical infrastructure particularly exposed to climate variability and climate change (ADB 2013b). Freshwater ecosystems have steadily degraded, particularly in the Mekong and Red River Deltas where patchworks of canals and levees have been built over the last two centuries with the goal of intensive rice production. Agricultural productivity and rural health have been undermined by heavy pesticide and fertiliser use (Berg et al. 2017) and are increasingly exposed to water pollution from industrial production (ICEM 2007).

These instabilities in Vietnam's water systems are tightly coupled with broader economic and social considerations. In order to maintain pace with annual growth in electricity demand of 10% to 12%, major additions in water-dependent power generation technologies are planned to 2030, such as coal (39 GW) and hydropower (11 GW) (Government of Vietnam 2016). Despite Vietnam's economic transition, 43% of the population remained dependent on agricultural activities in 2015 (World Bank 2017) and agriculture will continue as an important economic sector over coming decades (OECD 2015b). The health impacts and economic dislocation caused by extreme weather events, such as floods and droughts, and man-made disasters, such as dam failures, are a key constraint on rural households' livelihood security.

3.4.1.2. Water Governance in Vietnam

Similar to most countries, policy development and implementation are highly fragmented across the administrative scale of water resources governance in Vietnam (see Loan (2012) and Waibel (2010) for reviews). The key ministries for water resources management are the Ministry of Natural Resources and the Environment (MONRE) and the Ministry of Agriculture and Rural Development (MARD). MONRE's mandate covers state management of water and natural resources, hydro-meteorological assessment, and climate change. MARD's mandate includes irrigation works, rural water services, and the prevention and control of disasters, such as floods and droughts. Since the inception of MONRE in 2002, a series of reforms has addressed overlapping mandates and institutional competition between the two ministries (Molle & Hoanh

2011). Other national ministries have functions relevant to water governance, including the Ministry of Construction (urban water supply and sanitation), the Ministry of Health (drinking and household water), the Ministry of Industry and Trade (hydropower), the Ministry of Finance (allocation of state budget), and the Ministry of Planning and Investment (water infrastructure planning). Administration at the national level is supervised by the Government of Vietnam, which includes the Prime Minister and all Ministers.

Within all national ministries there are many agencies, including: (1) state-management agencies that develop policy, implement laws, and undertake administration; (2) non-business agencies that conduct research and provide education and other public services; and (3) business agencies, including state-owned enterprises. Many research and technical advisory agencies in MARD and MONRE are directly involved in water resources management; their mandates often overlap, but each typically has a specific function, a geographic focus in some cases, and many have sub-national units outside Hanoi that interact directly with sub-national levels of administration.

Laws, distribution of state finances, and overall objectives are determined at the national level, but fiscal decentralisation since the 1990s has progressively shifted responsibility for service delivery to the provinces and currently provides considerable autonomy to re-allocate expenditure. In irrigation management, for example, the provinces take the lead on irrigation planning, implementation, and operations and maintenance, but they submit plans and funding requests to the national level for review by the Ministry of Planning and Investment (with input from MARD agencies). Provincial People's Committees (PPCs) are the principal level of decision-making in provinces. A departmental structure replicates ministries and their functions at the national level, i.e. each province has a Department of Natural Resources and Environment (DONRE) and Department of Agriculture and Rural Development (DARD). Among the DARD state management agencies are sub-departments of irrigation management, while business agencies include the irrigation and drainage management companies (IDMCs) that operate and maintain irrigation schemes. Departments are supervised by their PPC and the equivalent national ministry. This dual supervisory arrangement is replicated at the district and commune scale, i.e. district offices are partially supervised by their provincial equivalents and the District People's Committee. In addition, commune-level agricultural cooperatives and water user groups (WUGs) are overseen by the district office of MARD/DARD and the Commune People's Committee. Figure 3.3 summarises the administrative scale of water governance in Vietnam.

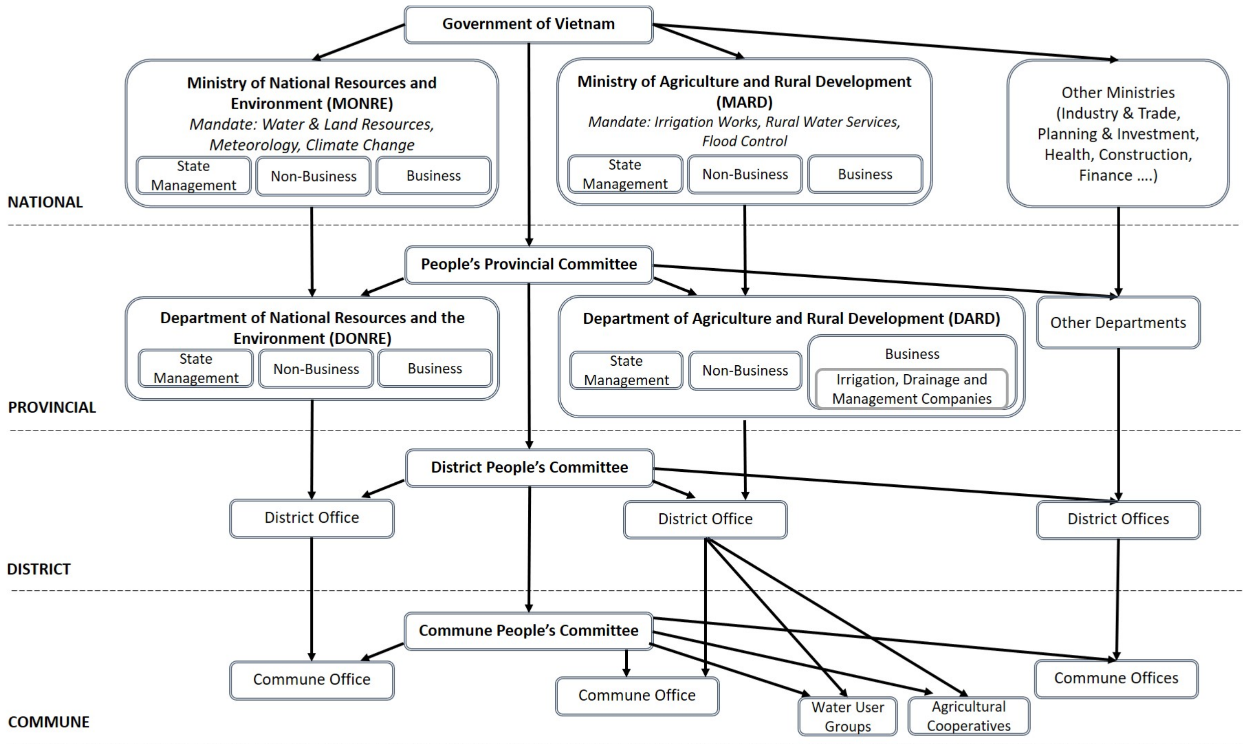

Figure 3.3. Overview of the administrative scale of water governance in Vietnam. Adapted from (Loan 2012; Waibel 2010). Arrows indicate a leadership relationship.

Policy development and planning are conducted at different levels of state administration. The national five-year Socio-Economic Development Strategy, master plans and broad objectives are developed by the Government of Vietnam. Otherwise, national-level planning often has a single sector focus. Ministries and state management agencies follow similar policy development procedures to each other but implement them differently. Collaboration can be limited between different levels of administration or agencies within the same ministry/department or province/district. Vertical and horizontal flows of information and knowledge do occur, but they are often blocked due to limited coordination between different levels of administration. Complementary to the administrative scale of governance is the Communist Party of Vietnam, which interacts with state management at all levels, plays a central role in defining national objectives, and is closely linked to the Fatherland Front and other mass organisations that support local service delivery, such as the Farmer's Union, Women's Union, and Veteran's Union.

Other decision-makers and groups within Vietnam's water governance networks include: farmers and the formal and informal groups to which they belong; private Vietnamese agribusinesses; international companies with domestic production facilities and global agribusinesses sourcing produce from Vietnam; and international organisations, including multi-lateral development banks, bilateral donor agencies, and global non-government organisations. Limited coordination across these actors and state administration has led to many ad hoc water re-allocation decisions in the past (Svendsen et al. 2005).

3.4.1.3. Agricultural Water Reforms in Vietnam

The Government of Vietnam is enacting policy plans and measures to address systemic water risks. Agricultural water reform is a key focus and the recent history of irrigation water pricing in Vietnam demonstrates how national policy generates sub-national governance dynamics. From 1995, irrigation service fees were collected in rural Vietnam by farmer-run WUGs or commune-level cooperatives. A small proportion of fees were combined with voluntary labor to maintain and manage tertiary canals, with the bulk of fees delivered to the Irrigation and Drainage Management Companies (IDMCs) that manage primary and secondary level canal systems. From 2009, irrigation services for most farmers were subsidised and paid directly to the IDMCs by the state (see Government of Vietnam (2008) for specific exemptions and cost norms). The reform sought to provide income relief to farmers, many of whom were struggling under production levies. Further, the reform intended to protect the financial viability of the IDMCs, many of which were trapped in a downward spiral of barriers to fee collection, low cost-recovery, and poor service delivery. Indeed, prior to the subsidy regime, the IDMC sector was the largest debtor to Electricity Vietnam (EVN), the state-owned electricity utility (Cook et al. 2013).

The benefits and costs of the irrigation service fee subsidy have been vigorously debated in Vietnam. A review of the fee waiver in three provinces during 2012 found that farmers had gained, on average, a small increase of about 400,000 VND (approximately US$20) of net income per year and IDMCs were financially stable again (Cook et al. 2013). Nevertheless, problems have emerged from fees no longer being sourced from farmers: farmers no longer have direct incentives to conserve water; IDMCs have reduced incentives to provide quality services to farmers; and cooperation between farmers, IDMCs, and WUGs has been undermined. The annual burden on the central budget of irrigation operations and management nearly doubled to 6.2 trillion VND (approximately $US 350 million) from 2009 onwards (OECD 2015b) and, given that significant investments in new and existing irrigation infrastructure are needed to diversify crop production and adapt to climate change (World Bank 2016), the subsidy program appears financially unsustainable.

Major droughts across Vietnam in 2015-2016 provided momentum for responses to the irrigation service fee issue and a discussion about the introduction of measures to increase agricultural water-use efficiency. Subsequent policy discussions have occurred in the context of broader plans to restructure irrigation and the agriculture sector by increasing productivity, enhancing resilience to extreme weather, and modernising supply-chains (Government of Vietnam 2013, 2014). Agencies within MARD are considering how the new national decree on public-private-partnerships (PPPs) (Government of Vietnam 2015b) could encourage private investment in irrigation infrastructure to augment dry-season water availability. The policy dialogues resulted in the 2017 Law on Irrigation that provides a legal framework for private investment in irrigation schemes, full-cost pricing of water services, and irrigation water to be managed as a commodity (National Assembly of Vietnam 2017).

3.4.1.4 Policy Pilots in Don Duong District of Lam Dong Province

Don Duong District, in the mountainous South-Central Highlands province of Lam Dong, is the planned site for state management agencies from MARD and Lam Dong DARD to pilot national innovations in water policy and management. The local economy is predominantly based on commercial agricultural commodities, such as coffee, tea, and vegetables. Similar to the national situation, demand- and supply-side pressures on water security are becoming major concerns. Trade-offs between water use for agriculture, tourism, industry, and hydropower are exposing vulnerability to extreme weather events: the 2015-2016 drought saw water shortages affect 60,000 ha of coffee and vegetable production fall by 30-40 percent.

The main growing region of Don Duong is a valley bisected by the Da Nhim river, an upstream tributary of the Dong Nai river that discharges into the ocean near Vietnam's commercial center, Ho Chi Minh City. Don Duong has a population of 91,000 and is a center of commercial vegetable and flower production. Due to the commercial orientation of agriculture and fertile soil, the average income of farming households is approximately double the national average (including both rural and urban households). Water availability in the dry season has become a key constraint: agricultural water demand is growing, and groundwater resources are becoming degraded by the predominant use of unregulated, on-farm wells. On-farm groundwater wells are the main source of irrigation water and a range of irrigation technologies are used from hand-watering to sprinklers to high-efficiency drip irrigation. The Da Nhim river is subject to poor water quality due to agricultural run-off.

Upstream of the vegetable growing area in Don Duong is the reservoir of the 160 MW Da Nhim hydropower plant which diverts water to neighboring Ninh Thuan province for electricity generation and irrigation. Built in the 1960s, the dam pre-dated agricultural activities in the Da Nhim valley and has limited capacity to supply downstream water due to operating rules and technical constraints. The reservoir is operated by a hydropower company which is majority owned by the state-owned electricity utility, Electricity Vietnam (EVN). The 2015-16 drought badly affected agricultural production in Don Duong and, although sufficient water was available in the reservoir to provide relief, no institutional mechanism existed to transfer it. National directives were issued in 2016 for the hydropower company to provide downstream flows during extreme droughts, but it is unclear how the directives will work in practice because of an upgrade to the power plant (due for completion in 2018) that will divert more water to Ninh Thuan under standard operations.

A policy pilot project is planned to trial national agricultural water management reforms in the irrigation command area of an agricultural cooperative in Don Duong. Partners in the pilot project include state management agencies of MARD and Lam Dong DARD, an international non-profit organisation (NPO), the agricultural cooperative, and district offices. The command area is adjacent to the Da Nhim river and distributes water from the river to farmers across a 95-ha area. The policy pilot plans to expand the command area to 250 ha and to invest in a larger pumping station, concreting of canals, and 100 on-field ponds for water storage. In addition to these supply-side measures, the project plans to: increase coverage of sprinkler and drip irrigation; expand education and training for farmers on water-use, fertiliser-use, and safe vegetable production; and pilot models for irrigation water service fees and a public-private-partnership in irrigation services.

3.4.2. ROAD Project

Given that agricultural water management in Don Duong is embedded in a complex food-energy-environment-water system, it is important for partners in the policy pilot to understand systemic risks and assess a range of interventions that can be integrated into the project and the broader district. To support this analysis, a team of researchers and practitioners under the Food Energy

Environment Water (FE2W) Network (http://www.fe2wnetwork.org) applied the ROAD process in Don Duong. The facilitation and research activities were undertaken by a project team comprising researchers from: the Institute of Policy and Strategy for Agriculture and Rural Development (IPSARD), a MARD research institute; the Australian National University (ANU); and other overseas research organisations, including the International Food Policy Research Institute. Technical inputs and peer review were provided throughout the project by government officials and researchers in Vietnam, researchers and practitioners from Australia, and local and international staff of the international NPO. Figure 3.4 provides a timeline of steps and events, including questions and actions adapted from the ROAD process that guided each step (Food Energy Environment Water Network 2017).

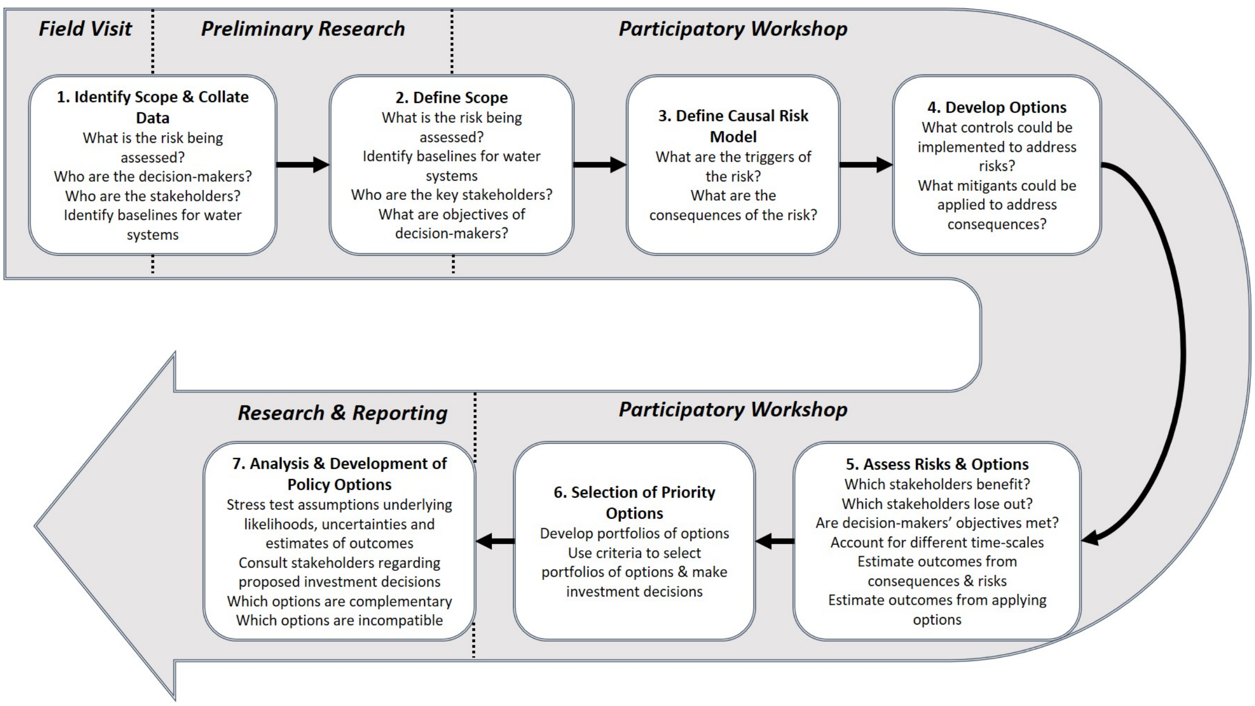

Figure 3.4. Summary of steps and activities during the ROAD project in Don Duong District.

3.4.2.1. Field Visit and Preliminary Research

The project was developed at a multi-day workshop outside Vietnam attended by members of the project team and researchers from the FE2W Network. Participants contested elements of the prototype ROAD process and its application in Don Duong. The project began with a field visit to Hanoi and Lam Dong that included: (1) an inception meeting in Hanoi with researchers from MARD and MONRE agencies; (2) a workshop at MARD headquarters where international researchers from the project team presented insights from international experience of agricultural water pricing and PPPs in irrigation; (3) a meeting between the project team and a MARD Vice-Minister; (4) meetings with the Lam Dong PPC, DARD, and DONRE to secure engagement and institutional support; and (4) a field visit to Don Duong district.

Quantitative data and qualitative reports were collected during and following the field visit by project team members from IPSARD. A household survey of thirty-nine farmers across Don Duong and interviews with six local officials was conducted in a separate field visit. The meetings, survey, interviews, and desk-based research of government reports provided the basis for an internal scoping report on key risks to water management in Lam Dong and Don Duong.

3.4.2.2. Participatory Workshop

The scoping report informed the design of a 1-day workshop during July 2016 in which participants collectively assessed agricultural water insecurity in Don Duong and identified priority policy options for further analysis by the project team. The workshop scope encompassed the entire district rather than the agricultural cooperative because implementation of the policy pilot had been delayed (and did not proceed until after the ROAD project). This scope accounted for the predominance of different irrigation systems in the cooperative (centralised surface water irrigation) and also the planned expansion area and remainder of the district (on-farm groundwater wells). Hence, the workshop had a broader geographic scope than the command area of the cooperative, but the results and subsequent analysis by the project team were still relevant to the planned location of the policy pilot.

The majority of workshop participants were Don Duong officials working in agricultural water management, many of whom farm their own land. A senior official and staff from each of Lam Dong DARD and DONRE attended, as well as the Vice-Chair of the District People's Committee and the leader of the agricultural cooperative. The number of participants varied throughout the workshop between a minimum of 8 and a maximum of 16. The workshop activities were designed by ANU researchers and tested in an educational setting beforehand. IPSARD staff revised the process before the workshop and facilitated the event, with ANU researchers present to provide technical support.

Participants in the workshop used a variety of tools and methods to define the risk assessment scope, build a causal risk model, and identify priority policy options. Participants defined the risk event as “water demand exceeds water supply in the dry season” and the stakeholders as “farmers” and “agribusinesses”. The following statements provided baselines for water systems in Don Duong: “Water scarcity is seasonal and its seriousness each year is increasingly variable due to climate change”, “Water allocation across different uses is being contested”, “There are concerns about the quality of surface water”, and “Farmers are not seriously measuring their water use, though some have invested in advanced irrigation systems”. Elements of this scope were drafted by the project team in advance and revised by participants during the workshop.

Facilitators of the workshop proposed that water releases from the hydropower reservoir be treated as an external factor given that this issue is managed at the level of national ministries. Consequently, participants did not incorporate the reservoir into the causal risk model or policy options despite the issue being raised by participants during the workshop. Participants’ three primary objectives were: “Increase farmers’ income through sustainable and high value-added agricultural production”, “Stable water supply for agricultural production”, and “Environmental protection in agricultural production areas (including farm waste treatment) to improve surface and ground water quality”.

The participants worked individually and collectively to build and define the causal risk model and portfolio of controls and mitigants which are depicted in Figure 3.5. Successive exercises evaluated: (i) strength of cause-effect relationships within the model; (ii) impacts of options across stakeholders, time, and consequences; (iii) compatibility of options with objectives; and (iv) whether options could generate negative impacts. For example, participants individually completed a template of the collectively defined causal risk model with likelihoods on a 5-interval scale from Very Low to Very High. That information was then used in a break-out group assessment of options. Throughout the assessment, participants were prompted to consider causes and effects across food-energy-environment-water systems by, for example, grouping individual ‘values’ in a Venn diagram of the four systems to develop collective objectives.

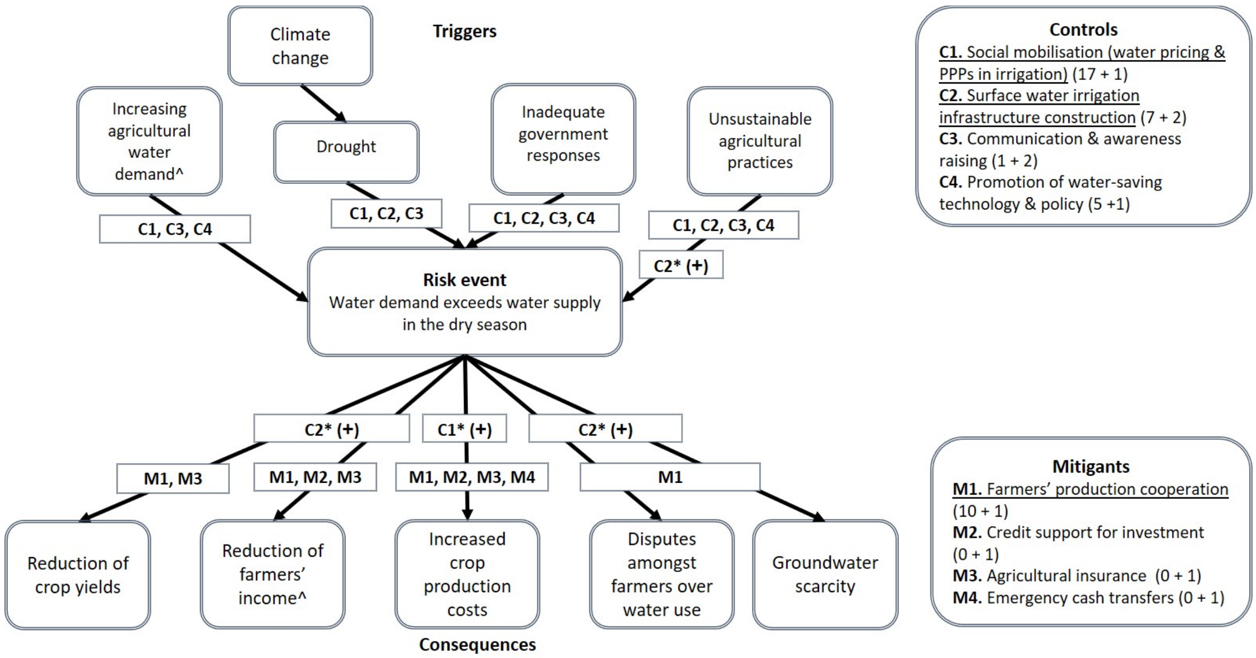

Figure 3.5. The causal risk model of dry season water scarcity in Don Duong District developed in the ROAD project. The causal risk model and the relevance of controls and mitigants to causal pathways were identified by workshop participants. The secondary impacts were identified by the project team. ^ represents the trigger or consequence considered to be the most important. Drivers and triggers were considered the same in this application. The controls and mitigants chosen for further analysis are underlined; the first number in brackets indicates the number of "effort" tokens allocated by individual participants and the other number indicates the additional collective allocation. * indicates secondary impacts of controls and (+) indicates the control could increase the likelihood of the trigger (risk) causing the risk (consequence), e.g. C1*(+) indicates that water pricing could increase the likelihood of dry-season water scarcity increasing crop production costs.

Following the assessment of the risk event and options, participants used a voting system based on the JUST-A-GRID method (Ferrand et al. 2014) to collectively select three priority options for analysis by the project team. Individuals were first given five tokens that represented the investment of effort and resources that should go into developing and implementing each option. The group was then given the collective task of distributing a further ten tokens.

The three priority options were: (1) mobilisation of non-state financial resources for constructing, operating, and managing irrigation infrastructure, including irrigation service fees and PPP arrangements; (2) construction of surface water irrigation infrastructure, including storage facilities and concrete transmission canals; and (3) encouraging cooperation between farmers in their agricultural production, including resource-sharing during emergencies and negotiation with agribusinesses. Finally, participants nominated supporting actions to implement the preferred policy options and filled in a feedback form regarding the causal risk modeling process used in the workshop.

3.4.2.3. Research and Reporting

The project team analysed the three priority options and developed a draft policy planning document regarding their implementation. One input to this document was a causal risk assessment of the irrigation infrastructure option across agricultural production, infrastructure, governance, and knowledge. The assessment was conducted in a workshop at the ANU by project team members and researchers with experience working in Vietnam. The proposed activities of the policy pilot provided the basis for considering how surface water irrigation would be developed throughout the district. A range of potential risk events and consequences were identified, including: (i) lack of surface water availability due to inadequate storage and increased upstream diversions by Da Nhim hydropower plant to Ninh Thuan province, (ii) reduced seepage of water from earthen canals into groundwater systems, (iii) higher run-off flow intensity and flood damages, (iv) increased pollution concentration in downstream areas and reduced yields, (v) reduced incomes due to higher energy costs and production losses, (vi) breakdown of centralised irrigation systems due to poor service delivery, and (vii) farmer discontent. These and other potential outcomes from surface water irrigation infrastructure construction are represented as secondary impacts within the causal risk model in Figure 3.5. A range of options were proposed by the project team to manage these secondary impacts, such as the use of green infrastructure to line canals and mandating sustainable production standards within the irrigation command area.

In addition to the risk assessment of infrastructure construction, the draft policy plan also outlined: (i) alternative storage technologies, such as managed aquifer recharge; (ii) theoretical and practical issues regarding agricultural water pricing; (iii) considerations for implementing PPPs in irrigation; (iv) proposals for potential PPP opportunities; (v) a proposal for establishing or strengthening three types of special farmer and community groups, including small groups of farmers producing the same crops, a high-level community water group, and existing social and kinship groups; and (vi) recommended investments in data collection given the limited quantitative data available to the ROAD project and officials' recognition of the need for more extensive and improved hydrological data collection, particularly for groundwater management. The underlying analysis for this policy plan included a static water balance model that supported workshop participants' perception of water scarcity as a dry season problem.

The project team returned to Lam Dong to present the draft policy plan to provincial and district officials that participated in the workshop. Staff from the MARD state-management agency and international NPO involved in the policy pilot accompanied the project team. Feedback from workshop participants and researchers from national agencies were incorporated into: (1) a revised version of the policy plan, (2) a policy brief on agricultural water pricing, and (3) a facilitator's guide to designing and implementing risk assessment processes for water management in Lam Dong. The preparation of output (3) drew on lessons from the ROAD project and was designed for use by provincial research agencies in Lam Dong involved in water management planning. All outputs were translated into Vietnamese. These outputs have since been incorporated into the international NPO's programs in Lam Dong, including the policy pilot in Don Duong.

3.5. Discussion

3.5.1. Knowledge and Information Transfer Across Governance Levels and Scales

The ROAD project in Don Duong demonstrated the importance of and barriers to information transfer across water governance networks. It is unlikely that special farmer production groups would have been identified as a priority if the risk assessment workshop had been conducted above the district level. Many of the district officials have direct contact with farmers or are part-time farmers themselves and, hence, could identify the local benefits of greater social cohesion under droughts. However, this proposal emerged from the particular circumstances of Don Duong where unregulated groundwater extraction has caused conflict between farmers. If that proposal were transferred up to the national level and deployed across Vietnam without regard to the context, then new groups could undermine existing social institutions in locations where stronger cooperation already exists.

3.5.1.1. Sharing Knowledge at the Sub-National Level

At the local level, irrigation services fees are a potentially divisive issue. That district-level officials supported this national-level priority is consistent with their experience: the major impacts of the 2015-2016 drought and awareness of the unsustainable trajectory of groundwater degradation in Don Duong. The uneven decline of aquifers across the district meant, however, that farmers in Don Duong did not necessarily share officials' supportive outlook and the field survey of farmers prior to the workshop did not contain references to irrigation service fees.

The contrast between the district officials' consent to the prospect of change and the project team's concerns in communicating that divisive prospect to farmers demonstrate a fundamental challenge of participatory processes: knowledge cannot just be communicated in one step. Instead, a sequence of activities is needed to socialise and legitimise the knowledge being transferred, particularly where a stakeholder may not agree or see the immediate benefits of a proposal. Nevertheless, anonymous written feedback provided by participants at the conclusion of the 1-day ROAD workshop underlines that a single participatory activity can still be useful in this regard: "The workshop exposed me to new knowledge", "The process is useful and I am more knowledgeable and I have an understanding of what is practically feasible", and "I have more understanding of how to use, manage, and exploit water more effectively".

3.5.1.2. Identifying Feedback Effects

A fundamental challenge of systemic risks is that there are no textbook solutions: policy interventions will generate their own cascade of changes that cannot be perfectly anticipated. The project team conducted a separate risk assessment of the irrigation infrastructure option to identify feedback effects that could amplify water insecurity and reduce resilience. This secondary assessment could be conducted with the same set of decision-makers that developed the options. In practice, however, decision-makers may not have the requisite scientific knowledge of system components or awareness of outcomes from similar actions in different locations. If this is the case, facilitators can broker the transfer of external knowledge and experience, or generate new knowledge through dedicated research on the responses of governance networks and physical systems to policy decisions. Researchers also require stakeholders' inputs to structure and validate secondary assessments and a two-way exchange of knowledge is needed to incorporate feedback effects into causal risk assessment.

3.5.1.3. Practical Limitations of Knowledge Transfer

The power of national ministries and provincial departments to set the management agenda at the district level was evident in the widespread support expressed for water pricing and PPPs during the causal risk modeling workshop. Senior provincial officials and the district leader were the most prominent speakers in plenary discussions. The project team anticipated that power imbalances might bias the results and structured the development of the causal risk model so that each participant first wrote down, for example, a trigger, and then individual nominations were collected and posted in front of the group for discussion. Moreover, staff from the MARD state management agency and international NPO were not invited by the project team to attend that workshop because their presence, and the investment they are bringing into Don Duong, could have influenced district officials. Notably, hierarchy was evident when a senior provincial official conducted the distribution of collective 'effort' tokens across policy options. Although the ranking did not change relative to the individual allocations, it was indicative of who had the authority over the final decision.

Reflecting on the constraints of hierarchy in a participatory setting and how the ROAD process could support future decision-making in Don Duong, the district leader proposed that causal risk assessment processes be conducted in separate workshops for farmers, businesses, and households so that their causal risk models could be shared with the administrative scale. Although resource constraints prevented multiple workshops in this ROAD project, this could be a useful approach to transferring knowledge between water governance scales and across levels of the administrative scale. Indeed, other multi-level participatory approaches to risk management have demonstrated the utility of breaking groups apart and then, in some cases, bringing them back together (Daniell, 2012). Replicating processes and producing comparable outputs across levels of administrative governance could also increase the legitimacy of alternative perceptions of systemic risks.

3.5.2. Credibility of the Risk Assessment Process

The ROAD pilot project could not have proceeded without the approval of decision-makers at different levels of the administrative scale. A cascade of consent occurred during the inception field visit, beginning with international researchers from the project team meeting the MARD Vice-Minister. At the provincial level, the Director of IPSARD accompanied the project team and introduced the project to the Vice-Chair of the Lam Dong PPC who provided his approval in front of DARD and DONRE officials. At the district level, a senior DARD official began introductions. Throughout this process, the reputation of the international researchers and Australian experience in water management were stressed by the IPSARD Director to impart credibility on the group and the ROAD project.

The credibility of risk assessment methods is also important. Workshop participants commented that causal risk assessment was a scientific approach, that it used logic, and focused on causes and solutions. In Vietnam, education and science are valued highly in society. This cultural context may have been reinforced by the Vice-Chair of the Lam Dong PPC being an agricultural scientist by training. Positive perceptions of a scientifically credible process, the technical expertise of the project team, and skilled facilitation all enable acceptance of participatory risk assessment.

3.5.3. Balancing Reductionism and Completeness in Systemic Risk Assessment

Complexity can be a barrier to making decisions and increases the likelihood of bad decisions. There is a trade-off in any risk assessment between reducing the system to a manageable size and excluding crucial components. Facilitators have an important role to play in achieving a practical scope; the exclusion of hydropower operations from the decision space of the participatory ROAD workshop is one such example. In addition, the project team had participants construct the core causal risk model with the project team later considering feedback effects separately. Importantly, such updating can incorporate system dynamics as they emerge, and this is why risk assessment processes, including ROAD, typically involve cyclical monitoring and evaluation of decisions. This process of updating and further appraisal allows for data analysis, including tests for the nonstationary nature of hydrological data (Milly et al. 2008) and what this implies in the context of water management (Daniell & Daniell 2006; Matalas 2012).

A potential avenue for balancing reductionism and completeness in a participatory setting is to identify key system variables, their baselines, and thresholds, or ‘tipping points’, which, if breached, send the system into a new state (see Lenton 2013). In the ROAD project, this approach was incorporated via qualitative baseline statements that were used as reference points for assessment of risks and options. Where more quantitative data is available, researchers and participants could jointly formulate thresholds for key variables, such as groundwater depth, end of wet-season rainfall, or the price of agricultural inputs and outputs.

Recent research on complex systems indicates that transitions or ‘regime shifts’ can be anticipated through slowing down in the rate of system recovery following shocks, flickering between alternative system states, and other early warning signs (Scheffer et al. 2012). Targeting measurement and structuring assessments around these features of a food-energy-environment-water systems provide an efficient means to manage risks and guide actions to increase resilience.

3.6. Conclusion

Drawing on concepts in complex systems, multi-level and multi-scale governance, and risk analysis, we provide insights about how to improve national level decision-making for systemic water risks. Specifically, we develop and test a participatory method for systemic risk assessment that can incorporate uncertain sub-national dynamics into national policy. Further, we provide guidance to scientists and researchers on how to work with stakeholders and facilitate resilient decision-making on complex risks.

An application of the ROAD process in Vietnam provided insights regarding knowledge transfer, the credibility of the risk assessment process, and the trade-offs between reductionism and incompleteness. Importantly, we have demonstrated the value of the ROAD process in a hierarchical governance context where decision-makers are unaccustomed to participatory processes and data and resources are limited. Hence, there is a strong likelihood that ROAD could support risk-based decision-making in both similar and less challenging contexts. A range of applications are needed to test and further develop the ROAD process across: risk and decision analysis methods, risks across food-energy-environment-water systems, and levels and scales of decision-making.

Chapter 4

Water Pricing or Irrigation Quotas?
Multipurpose Hydropower Regulation Under Risks

4.1. Introduction

Economists typically favour price-based approaches to allocating resources. Water is no exception, and for good reason: price signals provided by markets and regulations can efficiently reallocate water and infrastructure across different services, users, and time periods (Griffin 2015; Olmstead 2010). In particular, dynamic water pricing can provide households, industry, and farmers with incentives to adjust their consumption to scarcity, variable supply costs, and the optimal timing of infrastructure investment (e.g. Grafton et al. 2014; Gysi & Loucks 1971; Hanke & Davis 1971; Moncur & Pollock 1988). Importantly, this demand-side adjustment process means that a central regulator or water provider need not know the demand function of every water user for water to be allocated efficiently.

However, pricing is not always the best planning instrument when the future is uncertain. Weitzman (1974) showed that, in a general context, quantity-based instruments can be more efficient (i.e. generate greater net benefits) than prices if marginal benefits fall more slowly than marginal costs rise. If marginal benefits are relatively steep, prices are more efficient. Weitzman's initial analysis focused on a set of goods or commodities that are assumed to be desirable. His general insights on 'prices versus quantities' would go on to play a key role in subsequent work on pollution control (e.g. Adar & Griffin 1976; Newell & Pizer 2003; Parsons & Taschini 2013), and instrument choice for regulatory frameworks across a range of policy areas (see Goulder & Parry 2008 and Hepburn 2006 for reviews).

Figure 4.1 demonstrates the intuition of the 'prices vs. quantities' planning problem in the context of water allocation to a single consumer. Under perfect information regarding marginal benefits (MB) and marginal costs ($MC_{EXPECTED}$), there is a price-quantity pair ($p_{EXPECTED}$ and q_{QUOTA}) that maximises the total benefits of water provision across the supplier and consumer; regulating allocation by price or quantity is therefore equivalent. But if marginal cost is higher than expected (MC_{ACTUAL}), the water allocation in both cases is inefficient (i.e. net benefits are not maximised since $q \neq q^*$). The price instrument under allocates water ($q_{PRICE} < q^*$) and the quantity instrument over allocates water ($q_{QUOTA} > q^*$). The loss of efficiency, or 'deadweight loss', is determined by the initial instrument choice, the direction and magnitude of the changes in marginal costs, and the relative steepness of the marginal benefit and cost functions. In Figure 4.1a, I assume that the marginal benefit function, or water demand, is relatively flat compared to the marginal cost function because: (i) the consumer can substitute water for other goods as price rises and, (ii) additional supply requires additional infrastructure investments. In this case, the deadweight loss under the price instrument is lower ($DWL_p < DWL_q$). In Figure 4.1b, the consumer finds it harder to substitute water and marginal costs increase more slowly because infrastructure costs are front-loaded. Now quantities are the preferred regulatory instrument ($DWL_p > DWL_q$).

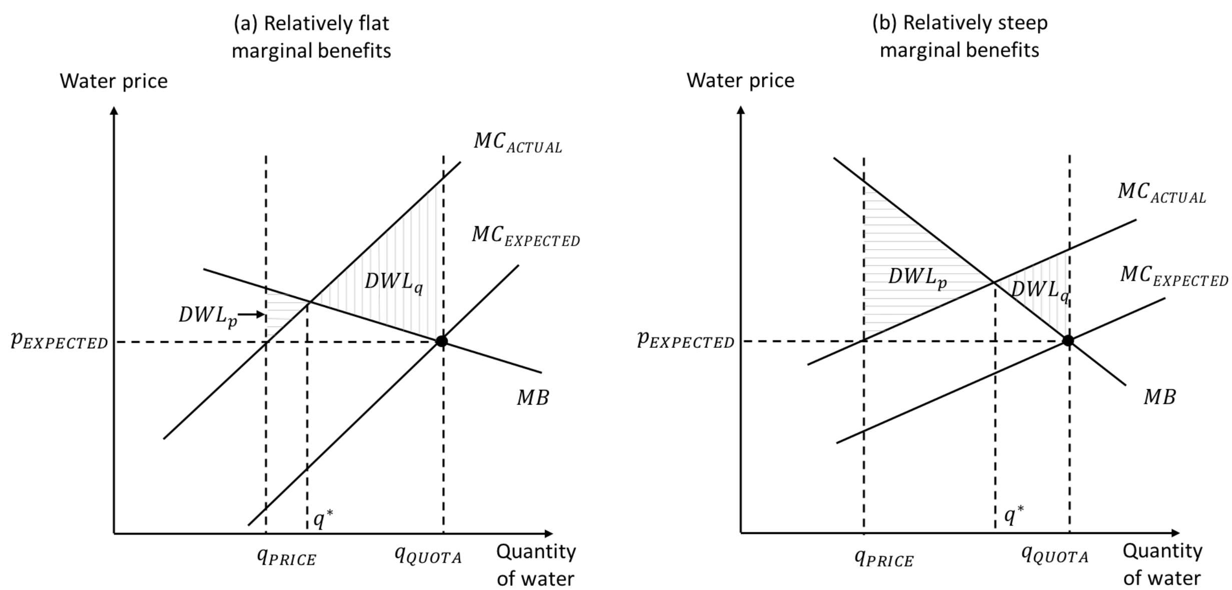

Figure 4.1. Illustration of the policy instrument choice problem: prices versus quantities for a single water consumer. Adapted from Hepburn (2006).

This simple illustration of the instrument choice problem highlights an important consideration for the regulation of water resources: under uncertain shifts in the marginal benefits and costs of water provision, *ex ante* price- and quantity-based planning instruments will both generate efficiency losses relative to the optimal *ex post* water allocation. Deviations between the expectation and realisation of costs and benefits render the optimum water allocation hypothetical. Yet, efficiency gains can be achieved if planning instruments for water allocation are selected according to their relative performance under the risks and uncertainty prevailing in a given policy context (see

Olmstead and Stavins 2009 for analysis of price and nonprice approaches to urban water conservation).

The hydropower sector is an arena of water governance with growing need for efficient regulation under dynamic conditions. Three key issues predominate. First, there are emerging trade-offs to manage. The hydropower industry and other stakeholders have advocated for increased investments in multipurpose hydropower development to provide essential water services, such as agricultural water storage, drinking water supplies, and flood control (e.g. Branche 2015; IEA Hydropower Agreement 2017; IFC/TNC 2017). Key multilateral banks and development agencies/facilities now emphasise multipurpose operations in their hydropower lending practices and policies (e.g. Rex et al. 2014). More large, multipurpose reservoirs could, in theory, help address major global challenges, such as climate change and securing access to food, energy, and water resources. But, in practice, the provision of additional water services, including environmental protection, typically involves opportunity costs: reduced hydropower generation, foregone profits, and, in some cases, additional infrastructure investments (Krchnak et al. 2009; Zeng et al. 2017). Efficient provision of water services from multipurpose reservoirs requires regulation of trade-offs between hydropower profits and broader public and private benefits.

Second, the task of regulating trade-offs is becoming more complex. Shifts in precipitation trends and weather variability under climate change will markedly alter reservoir inflows (van Vliet et al. 2016). Water demand is increasing globally under population and economic growth. The price that hydropower generation receives in markets will shift under the technological and policy changes associated with the renewable energy transition (Gaudard et al. 2016). Here, I think of the associated shifts in water supply, water demand, and hydroelectricity revenues as risks, or "events with uncertain consequences" (Wyrwoll et al. 2018). These risks alter the marginal benefits and marginal costs associated with the provision of water services from multipurpose reservoirs. Traditional approaches to hydropower regulation, on the other hand, are generally static, with multi-decade licenses stipulating, for example, minimum/maximum downstream flows, minimum/maximum storage levels, and fixed entitlements to water services. There is a growing need for dynamic regulation that provides hydropower operators with the flexibility and discretion to provide the efficient level of water services under risks (Pittock & Hartmann 2011; Viers 2011).

Finally, there is the matter of scale. Approximately 875 large hydropower reservoirs (>100 MW capacity) and 2775 medium-sized reservoirs (1 to 100 MW capacity) are estimated to be under construction or planned globally to 2035 (Zarfl et al. 2014). Many of these reservoirs will or could be multipurpose; the construction boom is focused on developing and emerging economies where water and energy security challenges are already acute, such as South and South-East Asia. Today, there already around 3900 multipurpose dams in operation globally that generate hydropower (Naughton et al. 2017). Opportunities exist to: (i) add additional purposes to existing, single-purpose hydropower reservoirs; (ii) generate energy services from single-purpose irrigation and water supply reservoirs; and (iii) build new reservoirs in areas of the world with untapped hydropower potential, such as Sub-Saharan Africa (Branche 2015; DOE 2016; IHA 2018). Both the upward trajectory of hydropower development and growing emphasis on multipurpose operations elevate the importance of getting hydropower regulation right.

A range of methods are used to allocate multipurpose reservoir storage across energy and water services (see Branche 2015 and IEA Hydropower Agreement 2017 for case studies). While price-based approaches to water allocation are broadly applied and researched in other areas of water management (see Griffin 2015; Johansson et al. 2002; OECD 2010; Olmstead & Stavins 2009; Wichelns 2013), their application to hydropower regulation has been limited to a few locations. On the other hand, quantity-based approaches (e.g. minimum downstream flows, minimum operating levels, and water abstraction rights) are common features of the water license regimes that govern hydropower operations in many countries (IFC 2015).

This Chapter examines the efficiency of using either irrigation water pricing or irrigation quotas to allocate multipurpose reservoir storage under risks. Specifically, I seek to better understand the conditions under which regulators may consider adopting water pricing to increase the total benefits of reservoir operation across hydropower and irrigation. Or, on the other hand, I seek to identify when water pricing does not provide relative efficiency gains compared to the guaranteed provision of a fixed volume of water to irrigators. I use stochastic dynamic programming to solve a model of a multipurpose hydropower reservoir where there are stochastic shifts in both the marginal cost of irrigation water (i.e. foregone hydroelectricity revenues) *and* the marginal benefit of irrigation water (i.e. variable irrigation water demand under weather variability). I extend this basic model to analyse risks across water supply, water demand, electricity prices, and energy policy. The remainder of this section provides a literature review and an outline of the Chapter's contribution. Section 4.2 develops a hydro-economic model of the operation and governance of a multipurpose hydropower reservoir. Section 4.3 calibrates the model to a case study in Tasmania, Australia. Section 4.4 presents the results, including the risk analysis and a sensitivity analysis of key parameters. Section 4.5 discusses the policy implications. Section 4.6 concludes with an overview of the study's limitations and provides directions for further research.

4.1.1. Literature Review and Contribution

There is a large literature on hydro-economic modelling of reservoir operations and the analysis of water systems (see Brown et al. 2015; Castelletti et al. 2008; and Harou et al. 2009 for reviews). Research into multipurpose hydropower operations has estimated the marginal value of water allocation across different uses and locations (Tilmant et al. 2008, 2009). Other studies have optimised reservoir operations under regulatory constraints (Edwards et al. 1999) and hydropower-irrigation trade-offs (Chatterjee et al. 1998). The costs and benefits of alternative hydropower governance regimes have been assessed (Guisández et al. 2013; Kotchen et al. 2006), with a particular focus on natural flow restoration (Rheinheimer et al. 2013; A. Tilmant et al. 2010) and environmental constraints (Harpman 1999). A number of studies have assessed the impacts of climate change and/or uncertain electricity prices on reservoir operations (Anghileri et al. 2018; Gaudard et al. 2016; Madani & Lund 2010; Steinschneider & Brown 2012) and developed financial instruments to manage hydrological risks (Brown & Carriquiry 2007; Foster et al. 2015).

Previous studies have considered the application of economic instruments to the governance of multipurpose reservoirs. Houston and Whittlesey (1986) use a linear programming model of the production of multiple crops to evaluate the sale of water rights from irrigators to hydropower producers, finding mutual benefits from trade. Brown and Carriquiry (2007) model options contracts for urban water suppliers to purchase water from agricultural users during drought years as an alternative to infrastructure expansion. The costs of purchasing water are smoothed through an inflows index-based insurance contract. Tilmant et al. (2009) model the transfer of water from irrigators to hydropower operators in a cascade of multipurpose reservoirs. A financial compensation mechanism provides the basis for efficient reallocation of water under dynamic weather conditions.

Maas et al. (2017) model water allocation markets and fixed water allocation for a multipurpose reservoir under dynamic water supply and water demand. The value of water infrastructure is quantified using a stochastic dynamic programming model. Water leasing markets maximise water infrastructure value, with fixed water allocations reducing value by up to 13% and causing storage augmentation benefits to become ambiguous. Foster et al. (2015) develop a set of index-based insurance contracts for hydropower generators to manage hydrological risk. Kern and Characklis (2017) estimate the costs of downstream flow-rate restrictions limiting a hydropower companies' capacity to respond to sub-daily electricity price shifts. The authors show that falling natural gas prices reduce the cost of these constraints and there are opportunities to reallocate water efficiently by enabling downstream water users to purchase restrictions (i.e. compensate the hydropower company for the opportunity cost of restricting changes in downstream flow-rates). In order to mitigate stochastic weather and electricity prices, a collar contract insures downstream users against the variable cost of restrictions.

The current Chapter is, to the best of the author's knowledge, the first study to model the application of volumetric water pricing to the regulation of multipurpose hydropower reservoirs. While most of the studies highlighted in the previous two paragraphs consider stochastic changes in either weather or electricity prices, I consider both. The major contribution is the extension of a basic model to analyse a range of risks associated with shifts in the marginal benefit and marginal cost of allocating water to irrigation. This extension provides general insights into the conditions under which water pricing or fixed irrigation quotas may be preferred as regulatory instruments.

4.2. Model of Multipurpose Hydropower Operations and Governance

I develop a stochastic dynamic programming model of reservoir operation and regulation to analyse the impact of water pricing and fixed irrigation quotas on the efficiency of water allocation under: (i) stochastic weather and electricity revenues, and (ii) risks associated with shifts in water supply, water demand, electricity prices, and energy policy. The model focuses on the optimisation problem of a profit-motivated hydropower company managing a multipurpose reservoir. Appendix 4.A1 summarises all variables and parameters.

The reservoir supplies water to electricity generation, irrigation, and environmental flows. The marginal benefit of allocating water to electricity production, irrigated agriculture, or storage varies according to stochastic changes in reservoir inflows, electricity market prices, and irrigation water demand. Alternative governance and operation scenarios are defined to compare the efficiency of price-based and (fixed) quantity-based regulation of irrigation water provision.

4.2.1. Hydropower Production

The quantity of hydroelectricity produced during period t is:

$$e_t = \frac{1}{a} \times x_t$$

where x_t is the volume of water scheduled for release from the reservoir to the hydropower plant during period t, and a is the fixed production parameter of water that specifies the volume of water required to produce a unit of electricity.

4.2.2. Water Balance and Weather

The volume of water stored in the reservoir at the beginning of period $t+1$, S_{t+1}, is the sum of the water entering and exiting the reservoir during period t:

$$S_{t+1} = min\left(S_t + \widetilde{f_t} - x_t - \widetilde{\iota_t} - \xi_t S_t - v_t, S_{MAX}\right) \quad (1)$$

where S_t is the volume of water in storage at the beginning of period t, $\widetilde{f_t}$ is inflows, $\widetilde{\iota_t}$ is irrigation water extractions, ξ_t is the seasonal rate of evaporation, v_t are seasonal environmental flows delivered to a connected river or lake, and S_{MAX} is the maximum storage volume. Water extractions for hydropower, irrigation, and environmental flows are rivalrous, with no reuse by, say, an irrigator downstream of the hydropower plant (see Figure 4.2). The hydropower operator schedules water allocation to electricity generation at the beginning of period t before inflows, irrigation extractions, and evaporation occur. Following Maas et al. (2017), a tilde accent (~) indicates variables which are not known when the hydropower operator makes the scheduling decision at the beginning of period t (i.e. irrigation extractions and inflows). Irrigators can access the residual water in storage after electricity generation is scheduled and inflows occur during period t, net of evaporation and environmental flows.

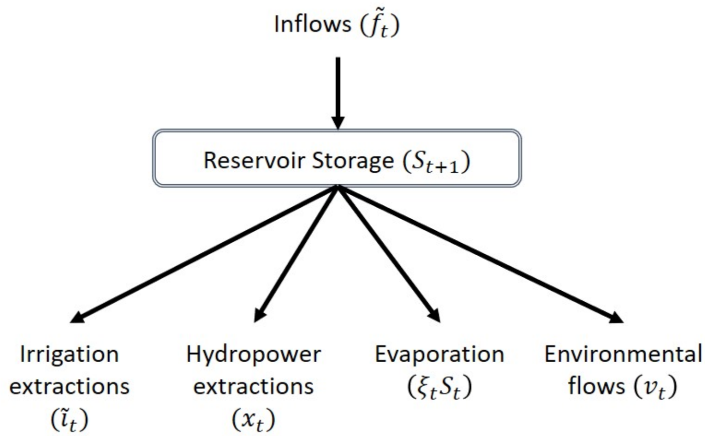

Figure 4.2. Overview of the water balance equation.

Inflows to the reservoir are a function of season type, weather variability, and random inflow shocks. I specify a bi-annual time-step and two seasons: summer ($\phi = 1$) and winter ($\phi = 2$). Environmental flows and the evaporation rate of storage vary according to the season:

$$v_t = \begin{Bmatrix} v_{\varphi_t=1} \text{ if } \phi = 1 \\ v_{\varphi_t=2} \text{ if } \phi = 2 \end{Bmatrix}; \; \xi_t = \begin{Bmatrix} \xi_{\varphi_t=1} \text{ if } \phi = 1 \\ \xi_{\varphi_t=2} \text{ if } \phi = 2 \end{Bmatrix}$$

with $\xi_{\varphi_t=1} > \xi_{\varphi_t=2}$ (i.e. the evaporation rate is higher in summer). The hydropower company considers a finite planning horizon $t = 0, 1, 2, \ldots\ldots, T$. Adapting the approach of Grafton et al. (2011), the model incorporates three weather types: wet (w), normal (n), and dry (d). The weather state in each season is a random variable correlated with weather in the previous season. Hence, a hydropower operator scheduling generation at the beginning of the current winter season, for example, forms an expectation regarding current period inflows based on the weather during the previous summer season. Formally, the weather state is defined by a discrete, first-order, time-heterogeneous Markov chain.

Probability of Dry, Normal, and Wet Weather in the forthcoming Winter Season ($\phi_t = 2$)					*Probability of Dry, Normal, and Wet Weather in the forthcoming Summer Season* ($\phi_t = 1$)			
$\tilde{C}_t$	$B_t = d$	$B_t = n$	$B_t = d$		$\tilde{C}_t$	$B_t = d$	$B_t = n$	$B_t = w$
d	0.6	0.3	0.6		d	0.5	0.2	0.3
n	0.3	0.4	0.3		n	0.4	0.6	0.4
w	0.1	0.3	0.1		w	0.1	0.2	0.3

Table 4.1. Transition probabilities between weather states: An example for forecasting weather at the beginning of the winter season (left) and summer season (right). Adapted from (Grafton et al. 2011).

Table 4.1 illustrates a hypothetical relationship between the forthcoming weather in the current season, $\tilde{C}_t$, and the previous season, B_t, at the beginning of period t. Each cell describes the probability of a weather type in the current period given the weather type during the previous period. For example, the probability of dry weather this winter given that last summer was dry is 0.6. The probabilities in each column add to 1. The transition of B_t over time is the probability distribution:

$$B_t = C_{t-1}$$

$$\tilde{C}_t = B_{t+1}$$

$$B_{t+1} = \begin{Bmatrix} d \text{ if the weather in the current period will be dry} \\ n \text{ if the weather in the current period will be normal} \\ w \text{ if the weather in the current period will be wet} \end{Bmatrix}$$

The combination of weather types and seasons means that there are six possible pairs of weather/season states in the model. Inflows into the reservoir are a function of the rainfall associated with these weather/season states, evapotranspiration in the reservoir catchment, upstream extractions, and groundwater seepage into the reservoir. Using subscripts to indicate summer ($\phi_t = 1$), winter ($\phi_t = 2$), and the weather type (d, n, w), I consider a matrix of six different inflow volumes:

$$F = \begin{Bmatrix} F_{\phi=1,d} & F_{\phi=1,n} & F_{\phi=1,w} \\ F_{\phi=2,d} & F_{\phi=2,n} & F_{\phi=2,w} \end{Bmatrix} \tag{2}$$

Inflows in the forthcoming period are:

$$\widetilde{f_t} = F(\phi_t, B_t) \times \varepsilon_t$$

where ε_t is a random shock with a discrete probability distribution, median = 1 and k values. A set of parameters, $\varepsilon^1, \varepsilon^2, \ldots., \varepsilon^k$, generates k proportional shifts in the aggregate inflows in the forthcoming season:

$$\varepsilon_t = \begin{cases} \varepsilon^1 \; w.p \; P^1 \\ \varepsilon^2 \; w.p \; P^2 \\ \quad \cdots \\ \varepsilon^k \; w.p \; P^k \end{cases}$$

with $\sum P^1 + P^2, \ldots, +P^k = 1$; $\varepsilon^1, \varepsilon^2, \ldots., \varepsilon^k \in (0,2)$ and $E(\varepsilon_t) = 1$. The random inflow shock integrates into the model: (i) natural variability in the rainfall associated with a given weather/season state, and (ii) random changes in upstream water extractions or land use.

4.2.3. Electricity and Carbon Markets

The marginal revenue from hydroelectricity generation, r_t, during period t is:

$$r_t = g_t + \theta^c c_t$$

where g_t is the forward price of electricity generation during period t. The electricity price is established through a futures market, swap, or other hedging instrument. The forward price for a unit of hydroelectricity traded in renewable energy certificate (REC) or carbon offset (CO) markets (henceforth ‘carbon markets’) is c_t; if this price is constant, then c_t is equal to some initial value, c_0. In both electricity and carbon markets, the hydropower operator is a price-taker (i.e. their generation decisions do not affect the market price) and the price for the forthcoming period is known when the scheduling decision is made. The hydropower operator participates in only one type of carbon market and the coefficient $\theta^c \in (0, 1)$ specifies the number of certificates or offset units accredited per unit of hydroelectricity generation. Under REC schemes, θ^c incorporates baselines and other conditions associated with market participation. For CO markets, θ^c is a conversion factor between the marginal value of hydroelectricity generation and the unit price of avoided greenhouse gas emissions, subject to project-specific parameters and market rules.

Electricity Markets

The representation of the electricity sector assumes the presence of competitive wholesale electricity markets with stochastic prices. The hydropower operator can sell electricity forward in a secondary market such that g_t is known at the beginning of period t when the generation planning decision is made. However, forward contracts only cover a single period and the profit-maximising operator must account for stochastic price changes in subsequent periods. The six-month forward electricity prices are uncorrelated with past weather and expectations regarding the current period's weather; this assumption may not hold in all real-world applications of the model.

Probability of Low, Medium, and High Electricity Price in period t+1			
M_t	$L_t = l$	$L_t = m$	$L_t = h$
l	0.3	0.2	0.2
m	0.4	0.5	0.4
h	0.3	0.3	0.4

Table 4.2. Example transition probabilities for electricity market price levels.

To account for uncertain price variability, I adapt the approach to modelling weather in Section 4.2.2 by considering three forward electricity market price levels: low (l), medium (m), high (h). Table 4.2 presents a hypothetical relationship between the electricity price level in period $t + 1$, $\widetilde{M}_t$, and the current period, L_t. There is no seasonal variation in price levels. This approach is analogous to the Markov regime-switching models for forecasting spot market prices (see Huisman & Mahieu 2003; Janczura & Weron 2010; Weron 2014).

Formally, the transition of L_t over time is

$$L_t = M_{t-1} \, , \widetilde{M}_t = L_{t+1}$$

$$L_{t+1} = \begin{Bmatrix} l \text{ if the electricity price will be low} \\ m \text{ if the electricity price will be medium} \\ h \text{ if the electricity price will be high} \end{Bmatrix}$$

Using the price type as a subscript, I consider three states for electricity market price levels:

$$L = \{L_l \quad L_m \quad L_h\}$$

with $g_t(L_l) < g_t(L_m) < g_t(L_h)$.

Carbon Markets

The average price received per unit of hydroelectricity in carbon markets in period t is defined as:

$$c_t = \begin{cases} c_0(1+\delta_c)^t \text{ if } t_{start} \leq t \leq t_{end} \\ 0 \text{ otherwise} \end{cases}$$

where t_{start} is the first operational period of the carbon market, t_{end} is the final period, c_0 is the starting price, and δ_c is the rate of price change per period. This deterministic specification enables analysis of the impact of announced policy changes, such as revision of targets and scheme introduction, and their impact on hydropower operators' returns from energy generation.

4.2.4. Water Demand and Irrigation Profit

A single irrigation offtake from the reservoir is managed by a company that provides water to farmers within an irrigation scheme. The hydropower reservoir is the scheme's only form of water storage. I consider two specifications for the extraction of irrigation water, $\boldsymbol{i_t}$, from the reservoir. In the first case, the seasonal quota of irrigation water is fixed:

$$\bar{\imath}_t = I(\phi_t)$$

$$I = \begin{Bmatrix} \bar{\imath}_{\phi=1} \\ \bar{\imath}_{\phi=2} \end{Bmatrix}$$

where $\bar{\imath}_{\phi=1}$and $\bar{\imath}_{\phi=2}$ are the fixed volumes of irrigation extractions during the summer and winter seasons respectively. In the second case, the volume of irrigation extractions varies according to the weather/season state (via shifts in farmers' aggregate demand for water) and the volumetric water price. Under water pricing, the hydropower operator does not know the current period volume of irrigation extractions when generation is scheduled at the beginning of period t. Irrigation extractions are determined by the intersection of the marginal benefit and marginal cost of irrigation water: farmers instruct the irrigation company to extract additional water until the additional revenue from an extra unit no longer exceeds the additional costs (i.e. the volumetric water price) for any farmers within the scheme. The volumetric water price is the opportunity cost to the hydropower company of providing irrigation water, i.e. the marginal value of foregone hydroelectricity revenue. I assume that the hydropower company incurs no fixed costs associated with irrigation water provision, such as infrastructure construction.

The irrigation company pays the hydropower operator to extract water from the reservoir and distributes the cost across members of the scheme through a water tariff. I disregard within-scheme costs of distributing water to farmers (e.g. pumping and infrastructure costs), assume full cost pass through within the same period, and specify that the irrigation company makes zero profits. During period $\boldsymbol{t}$, the irrigation company can access: (i) residual water storage in the reservoir after the hydropower operator has allocated water to electricity generation at the beginning of the period, and (ii) reservoir inflows that occur during period $\boldsymbol{t}$, net of evaporation and environmental flow deliveries.

To determine irrigation water demand under water pricing, I define a constant elasticity function for the marginal benefit of irrigation water. This function aggregates the demand functions of the farmers accessing the scheme:

$$\tilde{\iota}_t = \gamma_t (p_t)^{\alpha} \tag{3}$$

where $\gamma_t > 0$ is a parameter and $\alpha \in (-1, 0)$ is the constant price elasticity of demand. The price elasticity of demand lying between -1 and 0 indicates that: (i) water demand has an inverse relationship with price, and (ii) an increase in price of a given percentage will lead to a reduction in water demand of less than that percentage or, in other words, the price elasticity of water demand is inelastic.

The price per unit of water, p_t, is the marginal revenue of hydroelectricity generation divided by the production parameter of water:

$$p_t = \frac{r_t}{a}$$

Weather and season influence the extent to which irrigation water is needed to complement rainfall and meet crop water requirements. Hence, the marginal benefit of irrigation water increases (decreases) during dry (wet) periods. Consistent with the specification of inflows in Equation 2, I define six realisations of γ for each pair of weather (dry, normal, wet) and season (summer, winter) states:

$$\gamma = \begin{Bmatrix} \gamma_{\phi=1,d} & \gamma_{\phi=1,n} & \gamma_{\phi=1,w} \\ \gamma_{\phi=2,d} & \gamma_{\phi=2,n} & \gamma_{\phi=2,w} \end{Bmatrix}$$

Figure 4.3 shows how the marginal benefit of irrigation water and irrigation water extractions shift in response to weather and price variability. The marginal cost of irrigation water is the volumetric water price, p_t. Irrigation water deliveries increase in dry weather relative to normal weather, whereas wet weather sees reduced extractions (Figure 4.3a). For a given season/weather state, a higher (lower) price level will lead to lower (higher) irrigation water extractions (Figure 4.3b). Note that $\boldsymbol{\gamma}$ can be specified so that the fixed irrigation quota for a given season is equivalent to the volume of irrigation extractions under water pricing if, say, the weather is normal and electricity price level is medium. In this case, there is a duality in the price- and quantity-based approaches to regulating irrigation extractions.

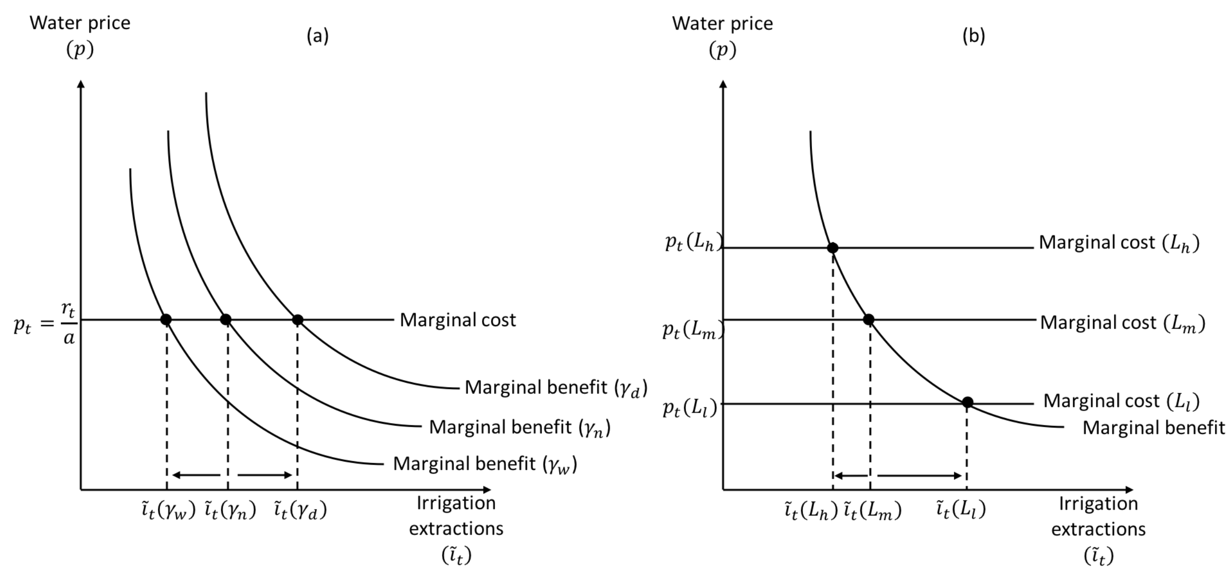

Figure 4.3. Variability in irrigation water demand according to (a) weather and (b) water price.

In order to calculate the benefits accruing to farmers under water pricing and fixed irrigation extractions, I manipulate the water demand function in Equation 3. The constant elasticity form of the function entails that demand will be nonzero for small values of i_t regardless of how high the price becomes, leading to infinite total benefits for a given volume of water delivery. I define a 'choke price', p_{CHOKE}, which is the highest price that a farmer in the irrigation scheme will pay for water, equivalent to the maximum marginal benefit of irrigation water, and a corresponding volume of water delivery, i_{CHOKE_t}, that varies according to the weather/season state. In the case of water pricing, demand for water becomes perfectly elastic (i.e. falls to zero) above the choke price.

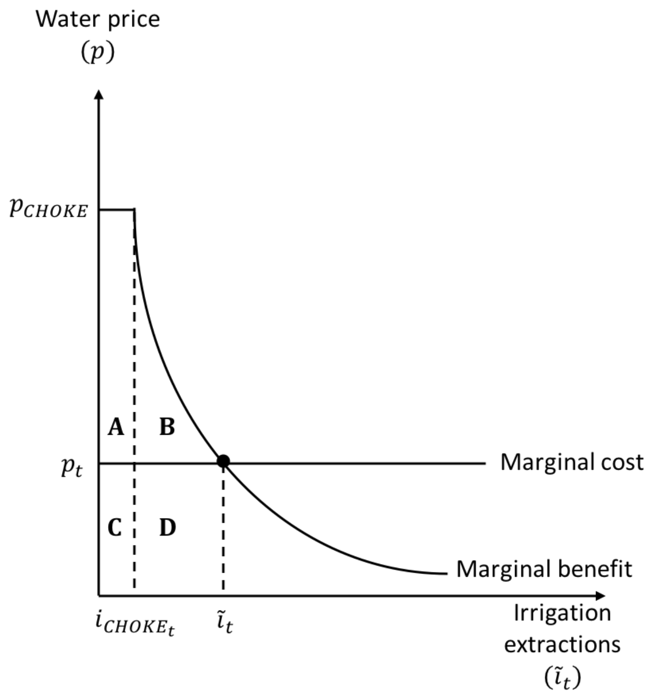

Figure 4.4. Choke price and calculation of irrigation net profit.

Next, I define an inverse demand function for the portion of the demand curve to the right of the choke volume by inverting Equation 3 so that

$$p_t = \left(\frac{\tilde{\imath}_t}{\gamma_t}\right)^{\frac{1}{\alpha}} \;\; \forall \;\; \tilde{\imath} \geq \; i_{CHOKE}$$

Farmers' net irrigation net profit is presented graphically in Figure 4.4. Under water pricing, net profit (Area A + B) = total benefits from water extractions (Area A + B + C + D) - total cost of water extractions (Area C + D). Under fixed irrigation extractions, there is no cost for water and irrigators accrue all of the total benefits (Area A + B + C + D).

For water pricing, net irrigation profit can be found by solving:

$$\pi_t^I(\tilde{\imath}_t) = \int_{i_{CHOKE_t}}^{\tilde{\imath}_t} p(s)ds + p_{CHOKE} \times i_{CHOKE_t} - p_t \times \tilde{\imath}_t$$

$$= \frac{\alpha}{\gamma_t^{\frac{1}{\alpha}}(\alpha+1)}\left(\tilde{\imath}_t^{\frac{\alpha+1}{\alpha}} - i_{CHOKE_t}^{\frac{\alpha+1}{\alpha}}\right) + p_{CHOKE} \times i_{CHOKE_t} - p_t \times \tilde{\imath}_t$$

$$i_{CHOKE_t} = i_{CHOKE_t}(\gamma_t(B_t))$$

$$i_{CHOKE_t} = \begin{cases} i_{CHOKE_{\phi=1,d}} & i_{CHOKE_{\phi=1,n}} & i_{CHOKE_{\phi=1,w}} \\ i_{CHOKE_{\phi=2,d}} & i_{CHOKE_{\phi=2,n}} & i_{CHOKE_{\phi=2,w}} \end{cases}$$

Assuming that both α and p_{CHOKE} are fixed, irrigation profits change via: (i) shifts in the water price that leads to a movement along the demand curve, and (ii) a change in the weather/season state that shifts the demand curve and establishes a new volume of water delivery at which the marginal cost of irrigation water equals the marginal benefit. The fixed choke price and shifts in the demand function mean that i_{CHOKE_t} varies and has six different values according to the summer/season state. Note that for $\tilde{\imath} \geq i_{CHOKE_t}$ the inelastic demand function means that, all other things being equal, higher water prices will reduce irrigation net profit and irrigation extractions at a decreasing rate as price increases.

In the case of fixed irrigation quotas, I calculate net irrigation profits by substituting $\tilde{\imath}_t$ with $\bar{\imath}_t$ in the water price case and omitting the cost of water extractions:

$$\pi_t^I(\bar{\imath}_t) = \frac{\alpha}{\gamma_t^{\frac{1}{\alpha}}(\alpha+1)}\left(\bar{\imath}_t^{\frac{\alpha+1}{\alpha}} - i_{CHOKE_t}^{\frac{\alpha+1}{\alpha}}\right) + i_{CHOKE_t} \times p_{CHOKE}$$

4.2.5. Operation Constraints

The available volume of water is bounded by a maximum level of storage, S_{MAX}, and a minimum level of storage, S_{MIN}, from which water can be extracted. Hydropower and irrigation extractions can only be supplied if reservoir storage is above S_{MIN}. Therefore, storage in period t is bounded:

$$S_{MIN} \leq S_t \leq S_{MAX} \tag{4}$$

Furthermore, the total volume of water extracted for hydropower in a given period is limited by physical and operational constraints:

$$x_t \leq x_{MAX} \tag{5}$$

$$x_{MAX} = \begin{cases} \hat{x}_t \; if \; \hat{x}_t \; \leq S_t - S_{RISK} \\ \max(0, S_t - S_{RISK}) \; otherwise \end{cases}$$

$$S_{MIN} < S_{RISK}$$

where x_{MAX} is the maximum volume of hydropower extractions; $\hat{x}_t$ is the maximum physical volume of water that transmission infrastructure can extract from the reservoir and convey to the power station in a given period; S_{RISK} is the level of storage required to manage environmental quality in the reservoir and ensure that irrigation extractions are guaranteed when storage levels are low. This operation constraint means that that the hydropower operator cannot extract water if storage is below S_{RISK} and, hence, there is a buffer level of storage maintained. Note that water can be extracted for irrigation below S_{RISK} but only down to S_{MIN}.

4.2.6. Profit Functions and Optimisation Problems

I assume that there are no fixed costs associated with electricity generation and irrigation water supply. These costs are not included because the focus of the model is on the variable opportunity cost of water provision, i.e. foregone hydropower revenue. In the case of fixed irrigation extractions, hydropower profits, π_t^H, are total hydroelectricity generation revenue:

$$\pi_t^H(L_t, x_t) = \frac{1}{a} \times x_t \times \; r_t(L_t)$$

In the case of water pricing, hydropower operator profits also encompass revenue from supplying irrigation water in the previous period. Hence hydropower profits are:

$$\pi_t^H(B_t, K_t, L_t, x_t) = \frac{1}{a} \times x_t \times \; r_t(L_t) \; + \; i_{t-1}(B_t, K_t) \times p_{t-1}(K_t)$$

where K_t is the electricity price level in period $t-1$.

The irrigation net profit function, π_t^I, for water pricing can be expressed as:

$$\pi_t^I(B_t, L_t) = \frac{\alpha}{\gamma_t(B_t)^{\frac{1}{\alpha}}(\alpha+1)}\left(\tilde{\iota}_t^{\frac{\alpha+1}{\alpha}}(B_t, L_t) - i_{CHOKE_t}^{\frac{\alpha+1}{\alpha}}(B_t)\right) + p_{CHOKE} \times i_{CHOKE_t}(B_t) - p_t(L_t) \times \tilde{\iota}_t(B_t, L_t)$$

and the equivalent equation for irrigation net profit under fixed irrigation quotas is:

$$\pi_t^I(B_t, L_t) = \frac{\alpha}{\gamma_t(B_t)^{\frac{1}{\alpha}}(\alpha+1)}\left(\bar{\iota}_t^{\frac{\alpha+1}{\alpha}} - i_{CHOKE_t}^{\frac{\alpha+1}{\alpha}}(B_t)\right) + i_{CHOKE_t}(B_t) \times p_{CHOKE}$$

The hydropower operator controls the volume of water released to the power station in each period to maximise the net present value of expected profits over time. In the case of water pricing, the irrigator maximises the within-period benefits of its water extractions subject to the water price. In the case of fixed quotas, the irrigation company does not make any decisions.

Figure 4.5 summarises the timing of decision-making and the realisation of variables within a single period where irrigation water pricing is in place.

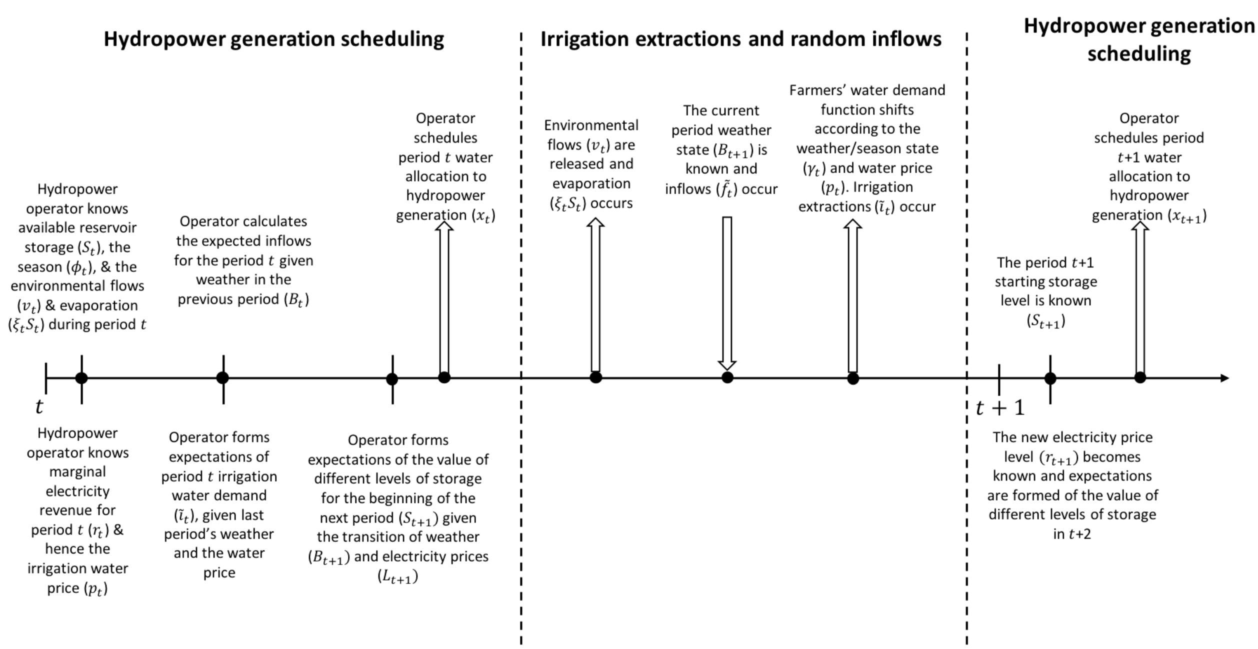

Figure 4.5. The timing of decision-making and the realisation of random variables under water pricing. Arrows indicate inflows and outflows from the reservoir.

I solve the hydropower operators' optimisation problem under (i) water pricing and (ii) fixed irrigation quotas. For (i), the irrigator's water extractions (and profits) in a given period are a function of the water price, the weather/season state, and the residual storage after hydropower extraction, environmental flow deliveries, and evaporation. The hydropower operator only directly controls the amount of water allocated to hydropower generation. The amount of irrigation revenues from the previous period vary according to irrigation water demand. For (ii), the irrigator's water extractions are fixed each period but profit varies as the marginal benefit function shifts with the weather/season state. The hydropower operator does not receive any irrigation revenues under fixed irrigation quotas.

I define a finite planning horizon, $t = (1,2, \dots . T)$, initial values of the state variables, and the transition probabilities in Tables 4.2 and 4.3. There are no irrigation extractions nor inflows in the terminal period. The profit of the hydropower operator in the final period is the sum of the value of the accessible water in storage and, where applicable, irrigation revenues from the penultimate period:

$$\pi_T^H(B_T, K_T, L_T, S_T) = (S_T - S_{MIN}) \times \frac{r_T(L_T)}{a} + i_{T-1}(B_T, K_T) \times p_{T-1}(K_T) \qquad (6)$$

The formal problem is

$$\max_{x_t} E_1 \sum_{t=1}^{T} \frac{\pi_t^H(B_t, K_t, L_t, x_t)}{(1+\rho)^t}$$

subject to: operation and regulatory constraints defined in Equations 4 and 5; the initial conditions for the season (ϕ_1), initial electricity price level (L_1), previous period's weather (B_1), and price level (K_1); the terminal profit condition (Equation 6); and the transition of the state variables (t, B_t, ϕ_t, K_t, L_t), including the water balance (Equation 1).

The transition of state variables is summarised below.

$$t = t + 1$$

$$\phi_{t+1} = 3 - \phi_t$$

$$S_{t+1} = min\big(S_t + \tilde{f}_t - x_t - \tilde{\iota}_t - \xi_t - v_t, S_{MAX}\big)$$

$$B_{t+1} = \begin{cases} d\ w.p.\ \Pr(\tilde{C}_t = d|B_t) \\ n\ w.p.\ \Pr(\tilde{C}_t = n|B_t) \\ w\ w.p.\ \Pr(\tilde{C}_t = w|B_t) \end{cases} \qquad L_{t+1} = \begin{cases} l\ w.p.\ \Pr(\tilde{M}_t = l|L_t) \\ m\ w.p.\ \Pr(\tilde{M}_t = m|L_t) \\ h\ w.p.\ \Pr(\tilde{M}_t = h|L_t) \end{cases}$$

$$K_{t+1} = L_t$$

The profit-maximising hydropower generation schedule from t=1 to t=T is found using stochastic dynamic programming (SDP). The Bellman equation is

$$V(S_t, \phi_t, B_t, K_t, L_t) = \max_{x_t} \left[\pi_t^H(S_t, \phi_t, B_t, K_t, L_t) + \frac{1}{1+\rho} E(S_{t+1}, \phi_{t+1}, B_{t+1}, K_{t+1}, L_{t+1})\right]$$

I solve the model with stochastic dynamic programming using backward induction. I briefly review the algorithm below. Beginning in $t = T$, the hydropower operator calculates the value of each combination of state variables for each period. In $t = T$, these values correspond to the different volumes of accessible storage, the current electricity price levels, and, in the case of water pricing, irrigation revenues associated with the different weather and price levels states in t=19. In t = 19, the hydropower operator calculates the optimal value of hydropower extractions for each combination of state variables. It does this on the basis of the profits it will receive in t = 19 across all possible hydropower extractions, plus the expected value of the level of storage at the beginning of t=20 resulting from those extractions. The operator goes through this iterative process for all possible volumes of hydropower extractions and combinations of state variables in each time period until t=1. A key assumption is that, no matter how the hydropower operator arrived at, say, a given level of storage in t=10, all decisions from t=1 to t=9 were optimal. Note that the value of a combination of state variables in t=1 includes the expected value of the optimal time-path from t=1 to t=20. The overall result, in this case, is two 6-dimensional matrices (i.e. one dimension per state variable, including time): one matrix defines the value of each possible combination of states, and the other defines the optimal level of hydropower extractions corresponding to each combination of those states.

In order to solve the model, starting conditions for the state variables are defined and the model is simulated forwards. Beginning in t=1, the hydropower operator schedules the optimal volume of electricity generation based on the storage level, season, price level, and last period's weather and price. Random shifts occur in the weather and price level, evaporation occurs, environmental flows are extracted, the irrigator extracts water, and there is a new starting level of reservoir storage (as per the decision-making sequence in Figure 4.5). Based on the resulting storage volume and values of the other state variables, the hydropower operator schedules the optimal volume of extractions in t=2, and so on. Conducting multiple simulations provides insights into the performance of different water allocation instruments across a range of time-paths for the state variables.

4.2.7. Dynamic (In)Efficiency Under Stochastic Weather and Prices

In the stochastic modelling framework described above, the hydropower operator makes an optimal water extraction decision each period on the basis of expected outcomes from a range of different values of random variables (e.g. inflows, irrigation extractions, and future electricity prices), not the actual values that eventually occur. In other words, the operator extracts water to maximise *expected* profits on the basis of the probabilistic transition of weather and electricity prices. This is important because it means that the optimal *ex ante* decision will almost always be different from the optimal *ex post* decision. Hence, the two water allocation instruments I examine here (i.e. water pricing and irrigation quotas) will both involve some deadweight efficiency loss in each period of each simulation simply because the future is uncertain when decisions are made. The task is to find the relative efficiency gains from deploying one instead of the other. Below I adapt the graphical approach to the general prices vs quantities choice problem in Figure 4.1 to illustrate where some of these relative gains may emerge.

First, consideration is required of how irrigation extractions and benefits change under variable weather and water prices. In Figure 4.6a the fixed irrigation quota is defined so that it equates to irrigation extractions under water pricing with a medium price and normal weather. If the weather is wet then extractions are lower under water pricing and irrigation benefits are higher by Area (A) under quotas. On the other hand, if the weather is dry then extractions are higher with water pricing and the gain in total benefits (Area $B + C$) from deploying that water allocation instrument is shared between net irrigation profits (Area B) and irrigation revenues to the hydropower operator (Area C). Figure 4.6b shows that, under normal weather, fixed quotas generate relatively higher total benefits under high prices (Area D), and pricing generates higher total benefits under low prices (Area $E + F$) that are distributed between net irrigation profits (Area E) and irrigation revenues for the hydropower company (Area F).

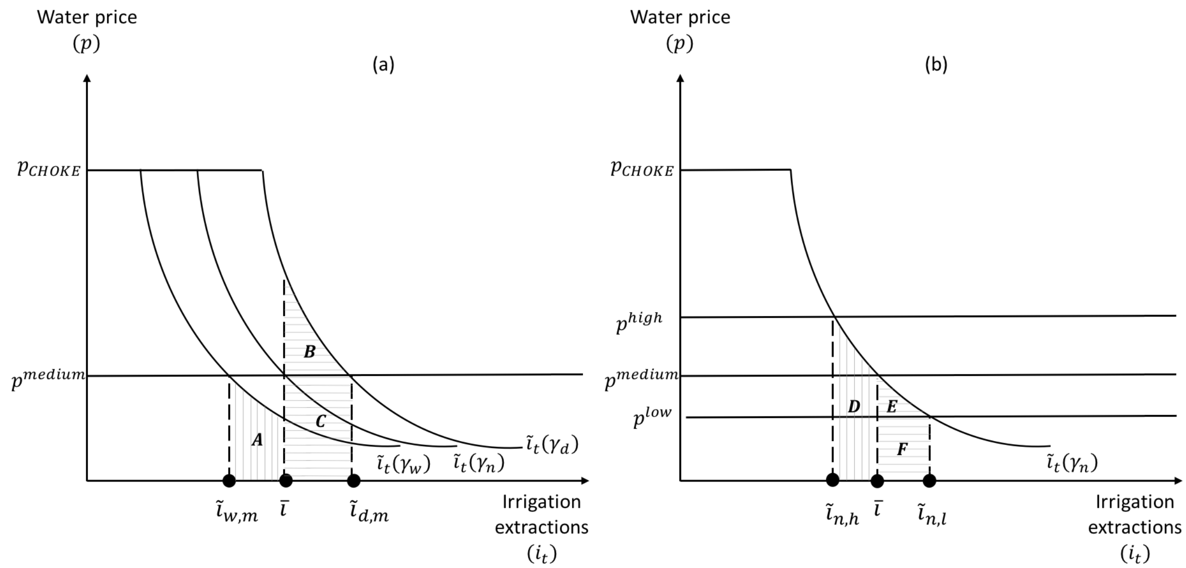

Figure 4.6. Change in benefits under pricing and quotas for variable weather and electricity prices.

Whether or not the shifts in irrigation extractions and benefits shown in Figure 4.6 will result in overall efficiency gains depends on the change in total benefits associated with the resulting transfers between different water uses and time periods. Identifying whether or not a specific transfer is efficient is difficult in a stochastic model: the hydropower operator's decisions are made with respect to dynamic profit expectations and the optimal hydropower extraction in, say, period t=3 is influenced by the joint probabilities of an extremely large number of future states that could occur from t=4 to t=20. The inherent complexity of optimising across an expanding state space is why large SDP models require significant computing power to be solved. However, if the gap between S_{MIN} and S_{RISK} is sufficiently large (i.e. so that there is no excess irrigation water demand under either allocation instrument), the discount rate is disregarded, and there are only two periods, then some preliminary insights can be obtained into how relative efficiency gains can emerge from either pricing or quotas.

The decision-making sequence shown in Figure 4.6 highlights a critical point in the allocation of water between irrigation in period t and hydropower in t+1. First, I assume that $i_t + S_{t+1} = z > S_{RISK} - S_{MIN}$, i.e. there is sufficient residual storage at the beginning of t+1 such that hydropower extractions, x_{t+1}, are possible. Second, I assume that the hydropower operator schedules all of that available storage such that $x_{t+1} = S_{t+1}$ and $z = i_t + x_{t+1}$. Recall that there can be a stochastic change in the electricity price at the beginning of t+1. This would equate to a shift in the marginal cost of irrigation water provision between the time that irrigation water is extracted at the end of t and hydropower is scheduled at the beginning of t+1. If this shift occurs, then there could be a relative efficiency gain depending on the water allocation instrument in place and the direction of shift in marginal cost (i.e. the water price).

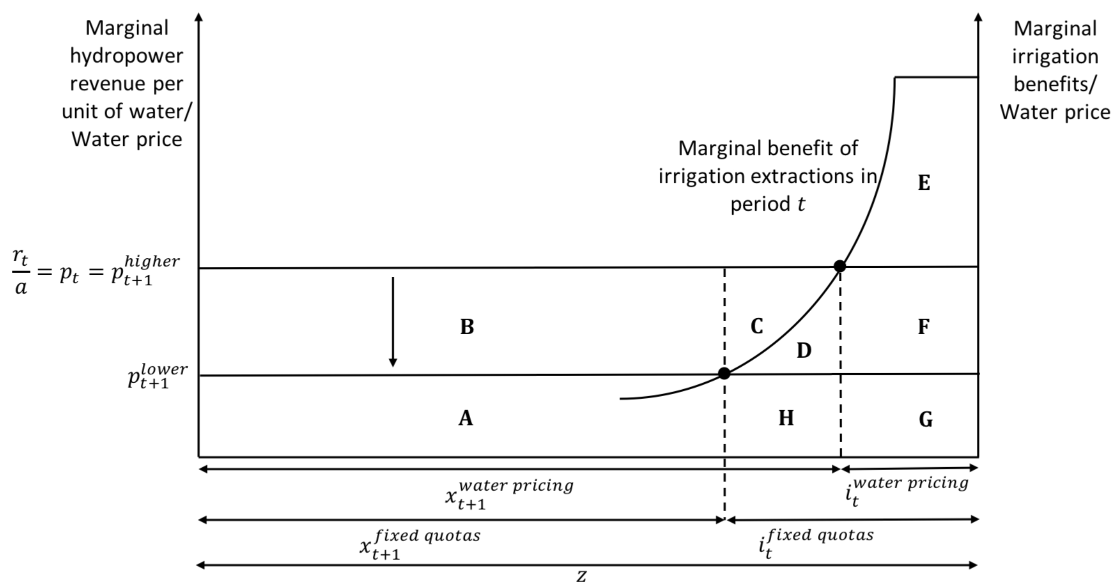

Figure 4.7. A downward shift in the marginal cost of irrigation water causes benefits to be higher under fixed quotas.

Figure 4.7 demonstrates. Here, irrigation extractions in period t are less under water pricing; this would be consistent with a higher electricity/water price in this example. The fixed irrigation quota equates to the efficient extraction under the lower price. Table 4.3 summarises the calculation of total benefits under water pricing and fixed quotas if the price stays the same or falls. If prices remain high, then total benefits under water pricing will be higher by the value of Area C. Conversely, if prices fall then fixed quotas generate Area D of additional benefits. Note the curvature of the water demand function implies Area C > Area D.

	Irrigation net benefits	Hydropower benefits (p_{t+1}^{higher})	Total benefits (p_{t+1}^{higher})	Hydropower benefits (p_{t+1}^{lower})	Total benefits (p_{t+1}^{lower})
Water pricing	E	A + B + C + D + F +G+H	A + B + C + D +E + F +G +H	A + F + G + H	A + E + F +G + H
Fixed quotas	D+ E + F + G + H	A + B	A + B + D + E + F + G + H	A	A + D + E + F+ G + H
Net benefits of water pricing compared to fixed quotas			C		- D

Table 4.3. Total benefits under pricing and quotas for constant and falling electricity prices.

Figure 4.8 shows the converse situation: higher extraction under water pricing with a lower initial water price. The outcomes are reversed: if the electricity price remains low then water pricing generates benefits of Area D, but quotas increase efficiency by Area C if prices become higher.

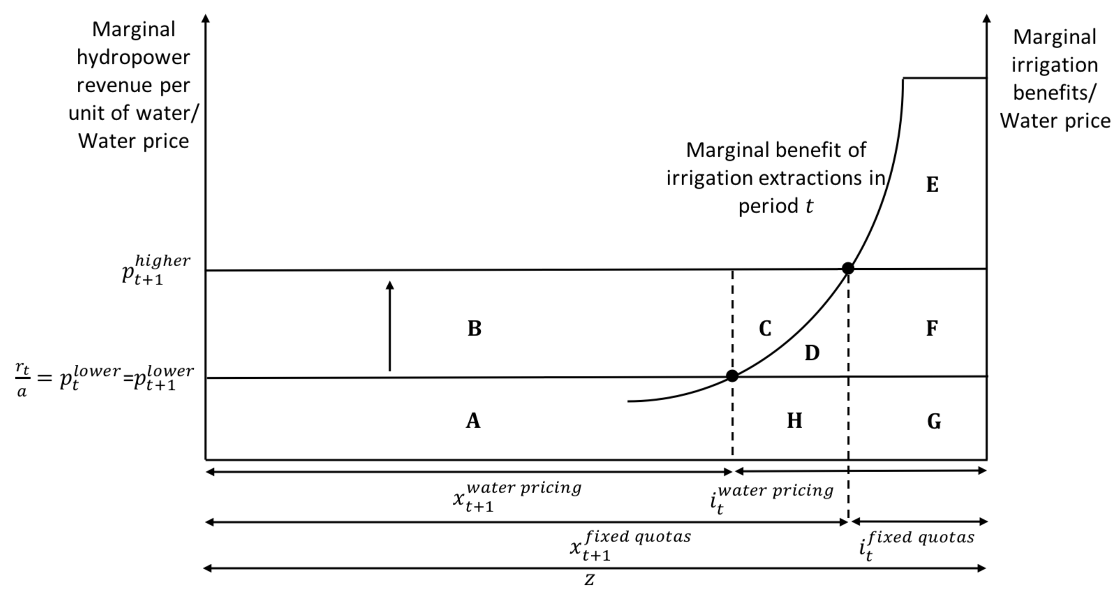

Figure 4.8. An upward shift in the marginal cost of irrigation water causes benefits to be higher under water pricing.

Figure 4.9 considers a situation where the change in prices is greater. Here, the initial water price is low in period t. The fixed quota is equivalent to some medium water price. If the electricity price level is higher in period t+1, the efficient allocation of water is x_{t+1}^{*high}, i.e. allocating more water to hydropower than occurs under either fixed quotas or water pricing. The difference is that efficiency losses are Area M + N + O under water pricing, but only Area O under the fixed quota. On the other hand, if prices were high in both t and $t + 1$ then water pricing would generate a relative gain in total benefits of Area O.

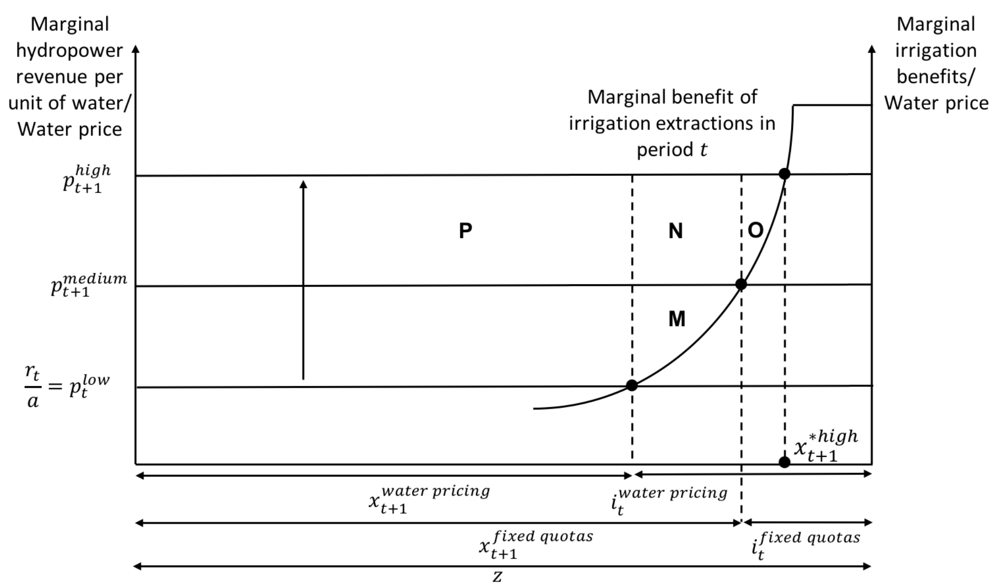

Figure 4.9. An upward shift in the marginal cost of irrigation water causes efficiency losses to be lower under fixed quotas.

In summary, the cases illustrated in Figures 4.6 to 4.9 provide insights into the potential causes of efficiency gains from the use of water pricing or fixed quotas to regulate irrigation extractions in multipurpose reservoirs. The relative efficiency gains from applying alternative water allocation instruments may be a function of: (i) the slope of the price elasticity of irrigation water demand; (ii) the difference between the three electricity price levels; (iii) the transition of electricity prices and, hence, water prices; and, in the case of Figure 4.7a, (iv) the relative shifts in water demand. These insights guide our sensitivity analysis of the model results in Section 4.4.

4.3. Model Calibration to Arthurs Lake, Tasmania

The model outlined in Section 4.2 is applied to Arthurs Lake, a multipurpose reservoir located in the Central Highlands of the Tasmania, an island state 240km off the coast of Australia. In this section I describe key elements of the system, relevant policy settings, and the parameterisation of the model. All monetary values are reported in 2018 Australian dollars (AUD).

4.3.1. The Arthurs Lake-Great Lake System

The Arthurs Lake catchment consists of 25,900 hectares that are primarily conservation areas with some agricultural land and small settlements. Average annual rainfall in the catchment is approximately 855 mm. The reservoir has a storage capacity of 448,790 ML and is operated as an auxiliary hydropower storage for the adjacent Great Lake (3,063,300 ML). Water is pumped from Arthurs Lake over a hill to the Great Lake via a pipeline with a 1.7MW capacity turbine on the downward side. Water held in the Great Lake is released to either the 313MW Poatina Power Station or the Shannon and Ouse Rivers. Downstream of Poatina is the 100MW Trevallyn Power Station.

Since 2014, water has been extracted from Arthurs Lake to supply irrigation water for the Midlands Water Scheme. In addition to providing water for energy generation and irrigation, Arthurs Lake is Tasmania's most popular recreational trout fishery and contains endangered, native Galaxiid fish species. Hydro Tasmania releases water from Arthurs Lake to manage water levels in the adjacent Woods Lake. Woods Lake is a shallow, man-made lake built to manage irrigation extractions from the downstream Lake River. Both Woods Lake and the Great Lake are also popular sites for recreational trout fishing and support populations of Galaxiid species. In addition to the Midlands Scheme and Woods Lake, water is also extracted for irrigation below the Poatina Power Station and from the Lake and Shannon Rivers. Figure 4.10 presents the main features of the Arthurs Lake-Great Lake system. The focus in this Chapter is the operation of Arthurs Lake to supply water to the Midlands Irrigation Scheme, Great Lake, and Woods Lake.

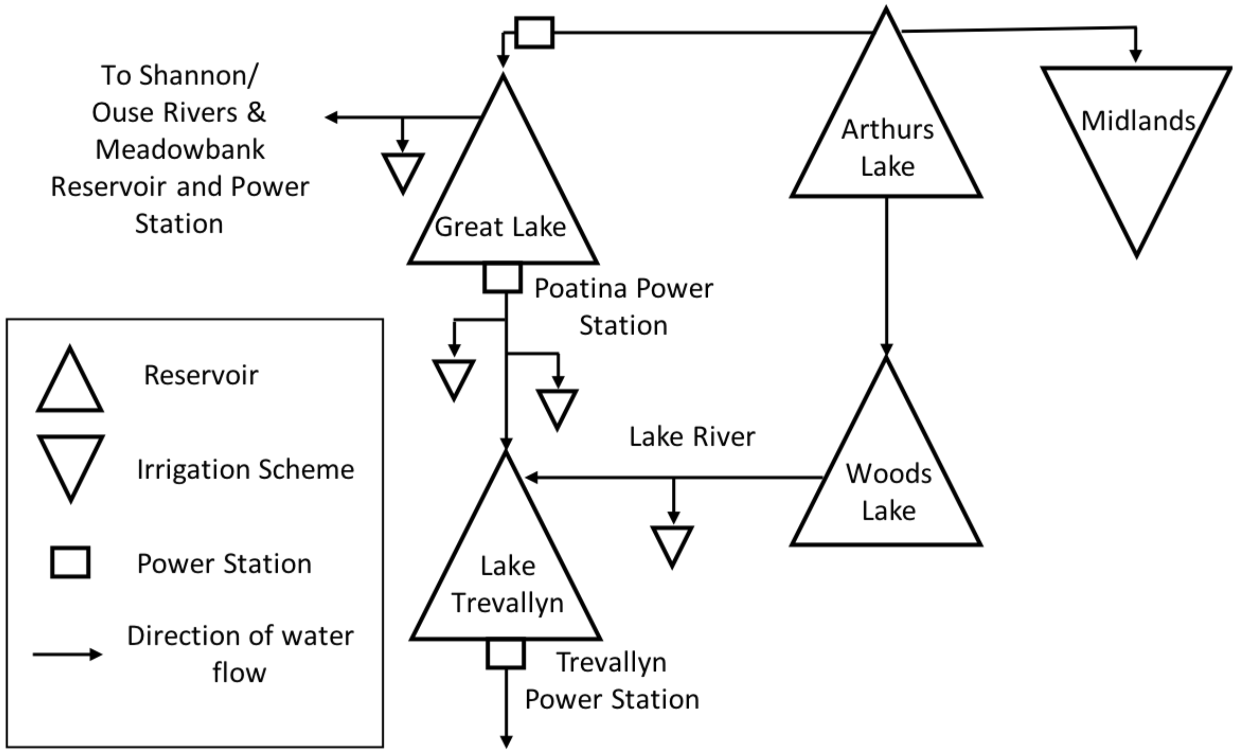

Figure 4.10. Schematic diagram of the Arthurs-Great Lake system.

4.3.2. Hydro Tasmania

Hydro Tasmania is a state-owned enterprise that pays dividends to the Tasmanian State Government. It generates approximately 90% of Tasmania's electricity through a network of around thirty hydropower stations and 50 dams. This network is operated as a system, with two large reservoirs (the Great Lake and Lake Gordon-Pedder) providing inter-annual storage. Hydro Tasmania sells electricity into Australia's wholesale National Electricity Market (NEM), which is separated into sub-national state regions including Tasmania. Since 2006, Hydro Tasmania has sold electricity into the Victorian region of the NEM via the 500MW capacity Basslink long-distance transmission cable. This connection also allows Tasmania to import electricity from the mainland. The company can also trade in: (i) electricity futures and options through the Australian Stock Exchange, and (ii) hedging instruments entered into with NEM participants (i.e. other generators, retailers, and large electricity consumers) directly or via a broker. Hydro Tasmania generates additional revenue by selling large-scale generation certificates (LGCs) to electricity retailers under Australia's Renewable Energy Target (RET) scheme. The company holds water and energy licenses that are respectively overseen by the Department of Primary Industries, Parks, Water and Environment (DPIPWE) and the Office of the Tasmania Economic Regulator (OTTER). In addition, Hydro Tasmania and the Inland Fisheries Service have agreements regarding the hydropower company's management of water levels in particular reservoirs.

4.3.3. The Midlands Water Scheme

The Midlands Water Scheme is operated by the state-owned Tasmania Irrigation (TI) company. The scheme was commissioned in 2014 and financed through federal and state government funding, the sale of water entitlements to farmers and investors, and private investment in on-farm infrastructure. The scheme encompasses 55,484 ha. Production activities prior to the commissioning included poppies, cereals, canola, pasture seeds, lucerne, potatoes, and livestock pasture (Tasmania Irrigation 2017a). The district is in the rain shadow of the Central Highlands (that includes the Arthur's Lake catchment) and receives approximately 500mm of rainfall per year. Areas of the new irrigation district may be suitable for dairy conversion and perennial horticulture for high-value crops (e.g. berries and hazelnuts) due to the augmentation of water supplies. Established irrigation schemes are located in the north of the broader Midlands region, including the Whitemore and Cressy-Longford schemes which accesses water from the Poatina tailrace. In 2010, the total value of agricultural production for the entire Midlands region (774,600 ha) was estimated to be $211.57 million (AK Consultants 2012).

The Midlands scheme owns and operates a 6MW hydropower station at the end of the delivery pipeline from Arthurs Lake. The scheme supplies farmers with up to 38,500 ML of water per year across two periods: 15,812 during a 150-day summer delivery period (October-February) and 22,688 ML during a 215-day winter delivery period (March-September). Participants in the scheme hold water entitlements that determine the amount of water that can be accessed per delivery period. Farmers pay a fixed charge per ML of entitlement each season and a volumetric price for water deliveries that incorporates: (i) the Hydro Tasmania water price, plus (ii) pumping costs to different points within the scheme, less (iii) a proportion of revenue from the scheme's power station. Trade in both water entitlements and seasonal allocations is facilitated by scheme management. As of 2018, the scheme is still in the early stages of operation: only 75% of available water entitlements had been purchased, trading activity was minimal in the 2016/17 growing season (1,540 ML for allocations), and the delivered volumes for the first three years (2014/15, 2015/16, 2016/17) were 17%, 67%, and 28% of capacity respectively (Tasmania Irrigation 2017b).

4.3.4. Pricing and Managing Water Extractions

Hydro Tasmania's water license stipulates that the company can enter into commercial arrangements for the sale of water at a price that represents the opportunity cost of foregone hydroelectricity revenue. Hydro Tasmania publishes a schedule of water prices at the beginning of each financial year for extractions from different reservoirs (e.g. Hydro Tasmania 2015, 2017) that specifies the foregone electricity per unit of water (MWh/ML) and the marginal value of foregone generation. The marginal value of hydroelectricity generation is calculated from the sum of: (i) the average forward electricity price for the charge period, (ii) half the value of foregone LGCs per unit of electricity, and (iii) a water scarcity premium. Prior to 2017, component (i) was calculated as the average of the over-the-counter Victorian Swap Contract Market price across separate annual, summer (December-April) and winter (July-November, May-June) prices. From 2017, the average electricity price is the annual forecast price determined by OTTER annually. The weighting of the foregone LGCs reflects that, on average, Hydro Tasmania's hydropower station are accredited with approximately half a MWh of renewable energy per unit of electricity generated due to the baselines set under the RET.

The water scarcity premium incorporates: (i) the higher prices that Hydro Tasmania bids into the wholesale market when water storages are low, and (ii) the need to import more electricity at peak prices from Victoria when local generation cannot sustainably supply Tasmania's demand. Prior to 2017, a water scarcity factor was calculated from a moving average of the previous two years of inflows and multiplied by the difference between peak and average electricity prices. In addition, the peak-average difference was calculated from Victorian swap contracts. From 2017 onwards, the water scarcity premium is calculated using a constant 5% water scarcity factor and the peak-average difference for the Tasmanian Regulated prices forecast by OTTER annually. A further change in 2017 was that Hydro Tasmania began calculating water prices for extractions from their storages on the basis of a five-year rolling average to insulate irrigators from a sharp upward shift in electricity prices; this averaging approach was subsequently extended to 10 years in 2018. However, the Midlands Water Scheme is exempt from this price smoothing as it is hedged against higher water prices via higher revenues generated by operating its 6MW power station.

Hydro Tasmania operates the Arthurs Lake reservoir according to storage operating rules associated with its water license and agreements with stakeholders. Environmental risk bands are defined for the endangered fish species in the lake: Medium (948-947.5 metres above sea level (MASL)); High (947.5-947 MASL); Extreme (Below 947 MASL). Tasmania Irrigation (TI) and Hydro Tasmania have entered into a renewable 25-year water supply agreement to achieve a minimum reservoir level of 949 MASL on 1 June and 950 MASL on 1 November each year. TI can extract up to 40,000 ML a year according to the pricing schedule determined at the beginning of each financial year. In addition, Hydro Tasmania has an agreement with the Inland Fisheries Service (IFS) to ensure the reservoir level is above 949 MASL during the brown trout angling season (1 August to 30 April). The IFS agreement is conditional on the Great Lake being above its Medium Environmental Risk Level; if it is not, the level targets are reduced by 1 metre. Hydro Tasmania also has a written agreement to pump water to Woods Lake to protect Galaxiid species and support trout fishing in that reservoir. Water is pumped from Arthurs Lake to Woods Lake to maintain the level of the latter above 736.2 MASL (10,689 ML). The maximum extraction rate of the pump from Arthurs Lake to the Great Lake is approximately 4.2 cubic metres per second, or approximately 131,725 ML per year. In practice, water is typically pumped from Arthurs to the Great Lake whenever the reservoir is above the levels stipulated by the TI water supply agreement.

4.3.5. Model Parameterisation

In order to model the operation of Arthurs Lake under fixed irrigation quotas and water pricing, I define two seasons: summer (October-March) and winter (April to September). The minimum storage volume is set at the bottom of the High Environmental Risk band (947 MASL) = 114,650 ML, rounded up to 115,000 ML to discretise storage volumes into 500 ML units. Similarly, the maximum storage volume is rounded up to 449,000 ML from 448,790 ML (952.82 MASL). The environmental risk level below which the hydropower operator cannot extract water (S_{RISK}) is set at the top of the medium environmental risk level (948 MASL) which equates to 164,000 ML. The median inflows associated with the six different weather/season states are estimated for the Arthurs Lake catchment from 1970-2016. The definition of weather types (dry, normal, wet) follows from Robinson et al. (2005) and Grafton et al. (2011). If rainfall during a winter/summer season is: (i) above the 75th percentile it is a wet winter/summer, (ii) below the 25th percentile it is a dry winter/summer; and (iii) equal to or between the 25th and 75th percentile it is a normal winter/summer. The inflow volumes by weather/season state are calculated using monthly rainfall data for the Miena gauge from 1970-2016 and average monthly evapotranspiration and evaporation data for the Central Highlands region (BOM 2018) (see Appendix 4.A2 for further details on this calculation and underlying assumptions). The random inflow shock is defined as a uniform probability distribution. The parameters that scale the random inflow shock are estimated by calculating the average ratio of the corresponding percentiles (20th and 80th, 40th and 60th) across all weather types and seasons (see Appendix 4.A3 for further details). The rate of evaporation from Arthurs Lake (by the storage volume at the beginning of the period) is estimated by: scaling seasonal pan evaporation estimates for Arthurs Lake catchment (BOM 2018) by the factor for Woods Lake used in Ling et al. (2009) (to accommodate water temperature and other factors decreasing actual evaporation from the reservoir's surface), estimating evaporation volume (by surface area) across all possible storage levels (S_{MIN} to S_{MAX}), and calculating a seasonal average rate of evaporation as a percentage of storage volume.

The electricity price levels are defined by adapting the inflow calculation approach to average monthly spot prices from the Victoria region of the NEM from 1999-2016. The electricity prices are adjusted for inflation and are reported in 2018 dollars. The transition probabilities between electricity price states are estimated by calculating conditional probabilities from the frequency of events within the observed time series (see Appendix 4.A4). The weather state transition is defined using the same method. I use the 2015 Q1 LGC spot market price of $41.11 as the starting carbon market price and assume no deterministic trend in the basic model; this specification is consistent with the relatively stable average price for LGCs from 2011 to 2015, after which there was a rapid increase to around $90 through 2015-2017. Trend and level shifts in marginal electricity revenues are captured in the risk analysis in Section 4.4.2.

Given the early stage of the Midlands Water Scheme (MWS) operations, I use the estimate of the price elasticity of seasonal water demand for Victoria's largest irrigation district calculated by Wheeler et al. (2008). This implies that for every 1% increase in the water price, irrigation water demand decreases by 0.81%. A choke price of $611 is defined on the basis of the highest reported price for water allocations in Tasmanian irrigation water markets from 2011-2016 (ABARES 2016). I calculate fixed water extractions, scaling parameters for the water demand function and choke volumes using the maximum seasonal extractions defined for the MWS, rainfall data for the MWS, the choke price, and other parameters already defined for prices and the water demand function (see Appendix 4.A5). Fixed irrigation quotas in each season equate to irrigation extractions under water pricing for normal weather and a medium electricity price level, i.e. there is typically a duality in price- and quantity-based planning.

The model only incorporates water extractions from Arthurs Lake. However, I assume that all water pumped from Arthurs Lake to the Great Lake is subsequently used in the same period to generate electricity at the Poatina and Trevallyn Power Stations. The factor for converting water into electricity consistent with this assumption is derived from Hydro Tasmania's water pricing schedule (Hydro Tasmania 2015) and includes foregone generation from both Poatina and Trevallyn Power Stations. The pumping capacity restriction (from Arthurs to the Great Lake) means that the maximum extractions for hydropower generation are 66,044 ML and 65,681 ML for winter and summer respectively. Electricity generation from Tod's Corner and the Midlands Scheme hydropower station are not incorporated into the model. The water scarcity component of Hydro Tasmania's irrigation water tariff and any within-scheme charges for water delivery are not incorporated either. Seasonal environmental flows delivered from Arthurs Lake to Woods Lake are assumed to be constant and estimated on the basis of historical shifts in storage levels for Woods Lake. Table 4.4 summarises the parameter values. Figure 4.11 shows the various permutations in the summer season for the marginal benefit and marginal cost of irrigation water, as well as the corresponding levels of irrigation extractions under water pricing. Since direct rainfall in the MWS command area is relatively evenly distributed across seasons, Figure 4.11 also approximates the corresponding marginal benefit functions and irrigation extractions for the winter season.

Parameter	Mathematical Notation	Value
Minimum and maximum storage volume	S_{MIN}, S_{MAX}	115000 ML, 449000 ML
Risk storage volume	S_{RISK}	164000 ML
Inflows, by season and weather type	$F = \begin{Bmatrix} f_{\phi=1,d} & f_{\phi=1,n} & f_{\phi=1,w} \\ f_{\phi=2,d} & f_{\phi=2,n} & f_{\phi=2,w} \end{Bmatrix}$	$\begin{Bmatrix} 18227 \text{ ML} & 22679 \text{ ML} & 39375 \text{ ML} \\ 59850 \text{ ML} & 88207 \text{ ML} & 122905 \text{ ML} \end{Bmatrix}$
Random inflow shock	ε_t	$\varepsilon_t = \begin{cases} 0.87 \text{ w.p } 0.2 \\ 0.97 \text{ w.p } 0.2 \\ 1 \text{ w.p } 0.2 \\ 1.03 \text{ w.p } 0.2 \\ 1.13 \text{ w.p } 0.2 \end{cases}$
Evaporation rate of storage	$\xi_t = \begin{Bmatrix} \xi_{\varphi_t=1} \\ \xi_{\varphi_t=2} \end{Bmatrix}$	$\begin{Bmatrix} 0.138 \\ 0.049 \end{Bmatrix}$
Seasonal environmental flows	$v_t = \begin{Bmatrix} v_{\varphi_t=1} \text{ if } \phi = 1 \\ v_{\varphi_t=2} \text{ if } \phi = 2 \end{Bmatrix}$	$\begin{Bmatrix} 4000 \text{ ML} \\ 1000 \text{ ML} \end{Bmatrix}$
Electricity price levels ($/MWh)	$L = \{L_l \quad L_m \quad L_h\}$	{$31.96 $44.40 $67.71}
Production parameter of water for conversion of hydropower releases into electricity (MWh/ML)	a	0.5272
Maximum extractions for hydropower	$x_{MAX,\phi_t} = \begin{Bmatrix} x_{MAX,\phi_t=1} \\ x_{MAX,\phi_t=2} \end{Bmatrix}$	$\begin{Bmatrix} 65681 \text{ ML} \\ 66044 \text{ ML} \end{Bmatrix}$
Price elasticity of water demand	α	-0.81
Fixed seasonal irrigation extractions (ML)	$\bar{\iota}_{\phi_t} = \begin{Bmatrix} \bar{\iota}_{\phi_t=1} \\ \bar{\iota}_{\phi_t=2} \end{Bmatrix}$	$\begin{Bmatrix} 15114 \text{ ML} \\ 14895 \text{ ML} \end{Bmatrix}$
Weather and electricity price transition matrices	*See Appendix 4.A3*	
Carbon market starting price ($/MWh)	c_0	$41.11
Accreditation per unit of hydroelectricity generated	θ^c	0.5
Scaling parameter for the water demand/marginal benefit function	$\gamma = \begin{Bmatrix} \gamma_{\phi=1,\ d} & \gamma_{\phi=1,\ n} & \gamma_{\phi=1,\ w} \\ \gamma_{\phi=2,\ d} & \gamma_{\phi=2,\ n} & \gamma_{\phi=2,\ w} \end{Bmatrix}$	952477 746125 503291 960030 735314 500033
Choke price for irrigation water ($/ML)	p_{CHOKE}	$611
Choke volume for irrigation extraction (ML by weather/season)	$\tilde{\iota}_{CHOKE} = \begin{Bmatrix} \tilde{\iota}_{CHOKE_{\phi=1,d}} & \tilde{\iota}_{CHOKE_{\phi=1,n}} & \tilde{\iota}_{CHOKE_{\phi=1,w}} \\ \tilde{\iota}_{CHOKE_{\phi=2,d}} & \tilde{\iota}_{CHOKE_{\phi=2,n}} & \tilde{\iota}_{CHOKE_{\phi=2,w}} \end{Bmatrix}$	$\begin{Bmatrix} 5274 \text{ ML} & 4131 \text{ ML} & 2787 \text{ ML} \\ 5316 \text{ ML} & 4072 \text{ ML} & 2769 \text{ ML} \end{Bmatrix}$
Number of time periods	t	20 seasons (10 years)
Initial reservoir volume	S_0	310000 ML
Discount factor (per seasonal time-step)	ρ	0.015

Table 4.4. Summary of parameters for the model calibration to Arthurs Lake.

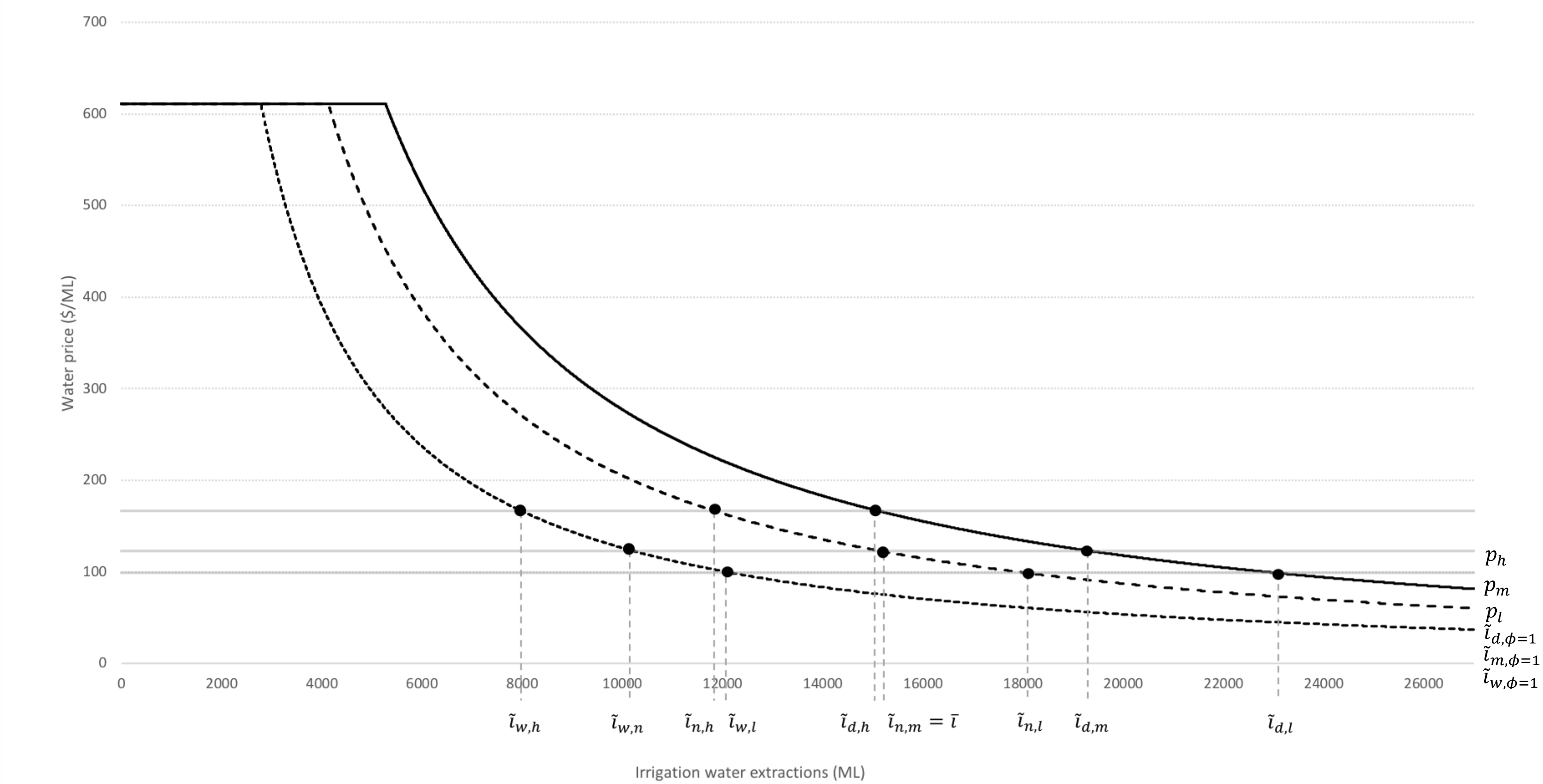

Figure 4.11. Summer irrigation water demand functions and irrigation extractions under alternative under weather/price pairs.

4.4. Results

4.4.1. Efficiency of Alternative Water Allocation Instruments

I calculate the total benefits of multipurpose reservoir operations across three alternative scenarios for regulating water allocation:

A. Hydropower only – There are no irrigation extractions and the reservoir is operated only for hydropower. The hydropower company schedules generation at the beginning of the period when current period inflows are unknown;

B. Fixed irrigation quotas – A fixed, seasonal volume of irrigation water is extracted from the reservoir each period after inflows and evaporation occur. Irrigators do not pay for water;

C. Water pricing – The irrigator extracts water from the reservoir according to shifts in the water demand function and water price. Current-period irrigation extractions are weather-dependent and, hence, unknown when the hydropower scheduling decision is made. The hydropower operator receives revenue in period t from period $t-1$ irrigation extractions.

I conduct 1000 random simulations of the three scenarios. The sequence of stochastic shifts in the weather, electricity price, and random shocks are the same in each simulation, i.e. for simulation j the time paths of the state variables, B_t, L_t, K_t, the random shock, ε_t, and inflows, $\tilde{f}_t$, are the same across different scenarios. I calculate the net present value (NPV) of benefits for hydropower and irrigation for each period within each simulation across the scenarios.

In order to understand the conditions under which water pricing leads to a more efficient water allocation, I examine both aggregate results and individual simulations. There are two reasons for this multi-faceted approach. First, there are multiple sources of stochastic change in the model: electricity prices, weather, and the random inflow shock. These sources of randomness affect decision-making and outcomes in multiple ways. Hence, the results of a given simulation do not indicate that fixed quotas will always outperform water pricing, or vice versa, from an efficiency perspective. The aggregate results presented in this section indicate the relative merits of different regulatory scenarios under an array of different time-paths for the stochastic variables and, importantly, the reasons causing aggregate variations in total benefits, such as the change in water extractions for a particular water use. On the other hand, aggregate results mask the potentially large distribution of outcomes across different simulations and may not provide significant insights into the dynamics of the model. Hence, I also present the results from particular simulations to understand how pricing or quotas can outperform the other as water allocation instruments.

	Hydropower		Irrigation		Total	
	Average water extractions (Standard deviation)	Average NPV of benefits (Standard deviation)	Average water extractions (Standard deviation)	Average NPV of benefits (Standard deviation)	Average water extractions (Standard deviation)	Average NPV of net benefits (Standard deviation)
(A) Hydro only	657.3 GL (65.3 GL)	\$81.5 million (\$9.1 million)	Not Applicable	Not Applicable	657.3 GL (65.3 GL)	\$81.5 million (\$9.1 million)
(B) Fixed irrigation quotas	474.6 GL (60.7 GL)	\$54.3 million (\$7.7 million)	300.1 GL (0 GL)	\$89.8 million (\$2.7 million)	774.7 GL (60.7 GL)	\$144.0 million (\$6.1 million)
(C) Water pricing	480.8 GL (71.4 GL)	\$86.6 million (\$8.4 million)	294.3 GL (18.6 GL)	\$58.0 million (\$3.1 million)	775.1 GL (59.6 GL)	\$144.6 million (\$6.0 million)

Table 4.5. Aggregate model results across regulatory scenarios. Averages reported for 1000 simulations. Each simulation experiences the same stochastic variations across periods as the corresponding simulation in a different scenario. The simulations span 20 seasons (10 years).

Table 4.5 presents a summary of aggregate results for the NPV of benefits and the volume of water extractions for Scenarios A, B, and C. On average, water pricing generates a small 0.4% improvement in the efficiency of water allocation compared to fixed irrigation quotas. This result is not surprising given that (i) the model is calibrated so that irrigation extractions under Scenario B and C are the same under normal weather and medium electricity prices, and (ii) the specification of the electricity price and weather transition result in a balanced distribution of different states; for the 20,000 time periods modelled, the price level is medium in 53% of periods, low in 22.5%, and high in 24.5%. The corresponding values for the weather state are 54.8% (normal), 22.3% (dry), and 22.9% (wet). Both multipurpose operation scenarios represent an overall improvement in total benefits compared to Scenario A. The large difference in hydropower and irrigation benefits across B and C reflect that irrigation water is provided free in B and the hydropower operator receives revenues from providing irrigation water in C. Although the primary focus in this section is total benefits, it is notable that, compared to Scenario A, the application of water pricing enables the hydropower operator to increase profits whilst extracting, on average, around 28% less water for electricity generation. The substantial standard deviations across water extractions and, to a lesser extent, benefits reflect the stochastic nature of the model.

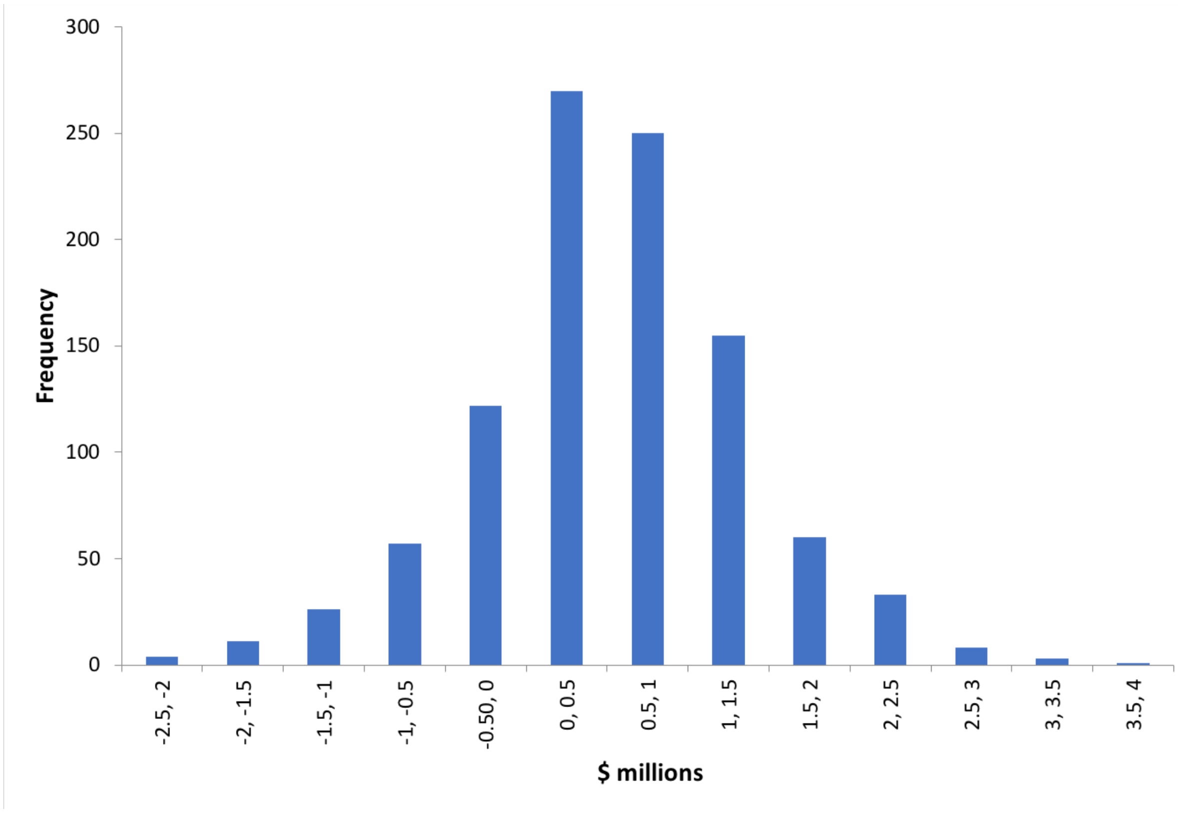

Figure 4.12. Frequency of the difference in NPV of Total Profits between Scenario C (water pricing) and Scenario B (fixed irrigation quotas) for 1000 model simulations. Positive values indicate that NPV Total Profits Scenario C > NPV Total Profits Scenario B.

Figure 4.12 shows the frequency of differences in total benefits between Scenarios C and B, e.g. NPV total benefits for simulation j under water pricing minus NPV total benefits for simulation j under fixed irrigation quotas. Although the differences remain fairly small, there are a significant number of simulations where either water pricing leads to a gain in net benefits in excess of $1 million or fixed quotas lead to a slightly more efficient water allocation.

In order to gain preliminary insights into the model's dynamics and how water is allocated by alternative regulatory instruments, I review the results from a particular simulation. Comparing Scenarios B and C, water pricing under this simulation generates an additional $1.3 million total benefits and, overall, hydropower extractions are higher (+ 8156 ML) and irrigation extractions are lower (- 4939 ML). Figure 4.13 presents the time-path of: (i) reservoir levels; (ii) inflows, the electricity price, and weather state; (iii) hydropower extractions; and (iv) irrigation extractions. Results are reported for Scenarios A, B, and C. The first point to note when comparing A to B and

C is that the introduction of irrigation extractions changes the operating mode of the reservoir from one where hydropower extractions vary seasonally but, in general, there is hydropower generated each season unless weather is very dry (Figure 4.13c). By contrast, water is typically extracted for hydropower in B and C only at the beginning of the summer season following winter inflows. This is because the hydropower operator cannot extract water if the reservoir level is below the environmental risk level (S_{RISK}) but irrigation extractions can (see Figure 4.14a).

Figures 4.13b and 4.13d show how, under water pricing, irrigation extractions increase (decrease) in response to dry (wet) weather states and low (high) electricity/water prices. These shifts are important drivers of the variation in outcomes compared to fixed quotas. Recall from Figure 4.5 that hydropower generation is scheduled at the beginning of the period before inflows and other outflows occur (i.e. irrigation, evaporation and environmental flows). Hence, increased (decreased) irrigation extractions in period t will reduce (increase) reservoir storage at the beginning of period $t + 1$ and decrease (increase) potential hydropower extractions in period $t + 1$, $t + 2$ and so on. For example, reduced irrigation extractions during periods 8 to 11 enable the hydropower operator to extract more water in periods 10, 11 and 13 when electricity revenues are higher. On the other hand, higher irrigation extractions during periods of dry weather and low water prices (periods 1, 6, 7 and 15) are followed by periods of low or medium electricity prices. Dynamic efficiency is increased because, on aggregate, the increased benefits associated with re-allocating water to one use exceeds the reduced benefits from less water allocated to the other.

Section 4.5 provides a detailed discussion of the policy implications of all modelling results. In short, however, it can be seen that, on aggregate, neither water pricing nor fixed quotas may represent a significant improvement over the other when quotas are calibrated to irrigation water demand prevailing under normal weather and medium price conditions. Once again, this result is expected given how the model is calibrated to approximate a duality in price- and quantity-based water allocations. On the other hand, the detailed results of a particular simulation provide insights into how some relative efficiency gains could emerge. I use the results from this basic model of stochastic weather and electricity prices as a baseline for the risk analysis further below.

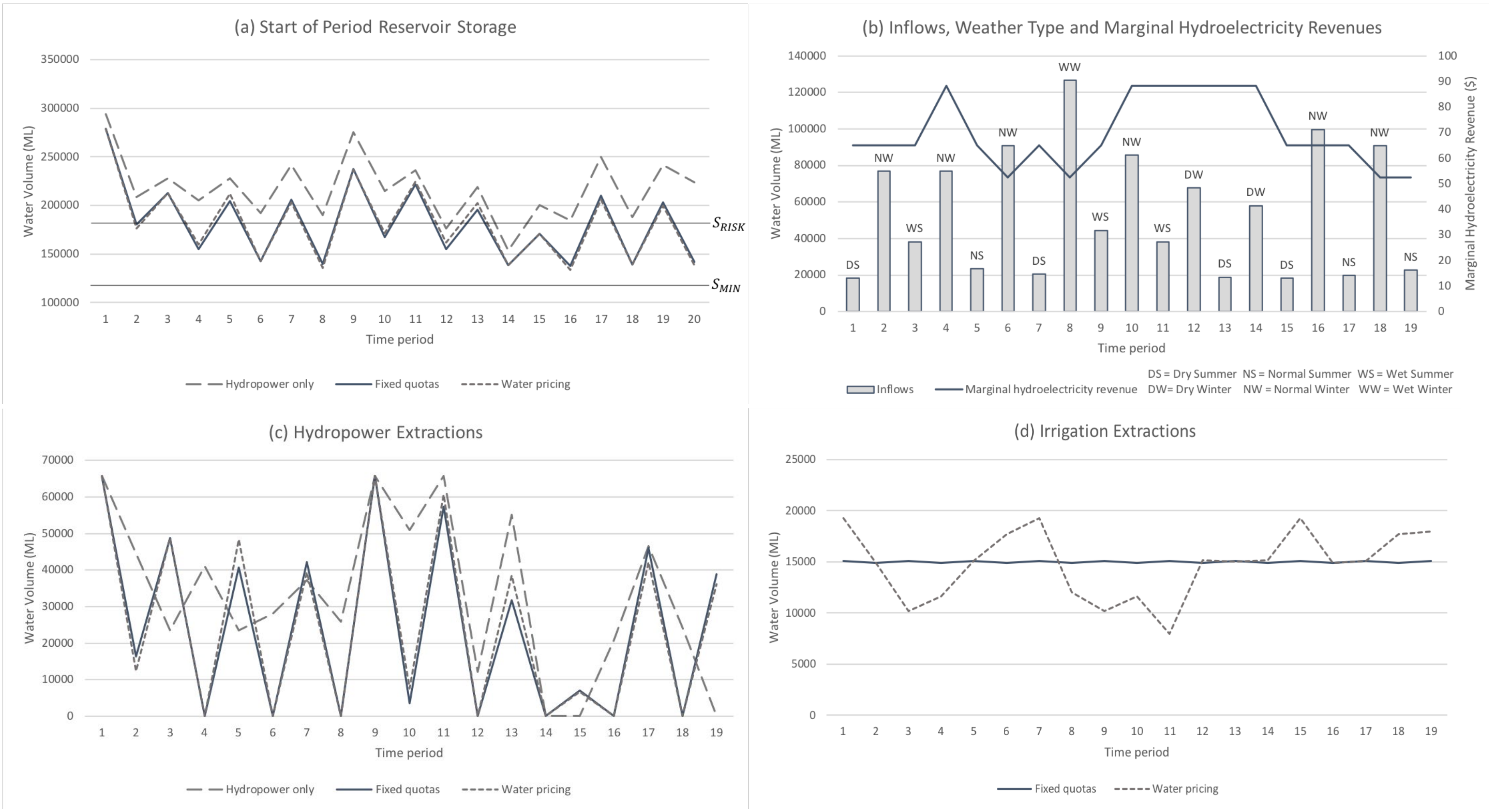

Figure 4.13. Time-path of key variables for a simulation where water pricing generates relative efficiency gains under the basic model specification.

4.4.2. Risk Analysis

I incorporate water and energy risks into Scenarios B and C to examine the conditions under which pricing or quotas allocate water more efficiently. Although these risks are calibrated to the conditions prevailing in the Arthurs Lake system considered here, they also reflect challenges facing regulators, hydropower operators, and irrigators globally. I replicate the process used in the basic specification of the models reported in Section 4.4.1, with 1000 simulations conducted of only Scenario B and Scenario C for each risk. Note that the transition of the weather and electricity price states remain the same for corresponding simulations, but the realisation of key variables, such as hydroelectricity revenues and irrigation extractions, may be different. The risks include:

- *Climate change* – Summer season inflows are reduced by 60% for all weather types; winter season inflows are reduced by 25% for all weather types. These shifts correspond to projected changes in run-off for the Arthurs Lake catchment by 2030 compared to historical climate (CSIRO 2009). The random inflow shock and irrigation water demand are unchanged.

- *Price spike* – The high electricity price level increases from \$67.71 to \$102.31. The latter value is the Victorian average wholesale spot price of electricity in the first quarter of 2018. Historic price spikes occurred around this period in Australia's National Electricity Market because policy uncertainty caused deferment of investment in new generation (to replace retiring coal-plants) and, in turn, increased vulnerability of the system to high demand events. In a broader context, such price spikes could also reflect: extreme weather events; shocks to coal and gas supply markets, such as transportation bottlenecks or processing plant failures; failure of large thermal plants and interconnections; sudden retirement of large generation plants; and exercise of market power by large generators in wholesale markets with limited competition.

- *Energy policy change* – I consider two variations: (i) The carbon market ends in t=10, causing a downward level effect in hydroelectricity revenues and water prices, and (ii) the carbon market is introduced in t=10. In each case, these are deterministic changes that the hydropower operator is aware of in advance. For the Arthurs Lake system, (i) reflects the sharp fall in the LGC spot market price expected in 2021-2022 due to a shift in 2020 from a rising to fixed target under the Australian Renewable Energy Target. More broadly, both (i) and (ii) reflect medium- and long-term level effects that can occur in electricity markets due to other policy changes, such as: the introduction, removal, or other reform of carbon pricing; deregulation of wholesale markets; and changes to the dispatch merit order in centrally planned markets.

- *Price trend* – Once again, I consider two variations: (i) a 3.8% seasonal increase in the LGC price such that it rises from \$44.11 in t=1 to \$83.50 in t=20, (ii) an equivalent percentage decrease in the LGC price such that it falls from \$44.11 in t=1 to \$19.31 in t=20. Variation (i) approximates the peak price that occurred in the Australian REC market in 2017-2018 due to excess demand for LGCs caused by under-investment in new renewable energy generation during a period of policy uncertainty. Since only half the volume of generation is attributed to LGCs, marginal hydroelectricity revenues increase or decrease by 1.75% per season. Although the price trend emerges from the carbon market component of hydroelectricity revenues, these shifts could also represent long-term trends associated with electricity market risks, such as: phased retirement of coal-fired power plants; entrance of new generation plants; and technological change, such as increasing uptake of electric vehicles.

- *Increasing irrigation water demand* – The scaling parameter of the irrigation water demand function (γ) and corresponding choke volume (i_{CHOKE}) shift 3.5% each season for each weather/season state. In the case of the Arthurs Lake system, this growth models increasing uptake of higher value agricultural production in the Midlands Water Scheme, and the broader expansion of high-value irrigation that is central to long-term economic planning in Tasmania (see West 2009). In the case of water pricing, this means that by t=19 irrigation water extractions would be 85% higher for the corresponding weather type. For example, a dry season with medium electricity price would involve 15,644 ML irrigation extractions in t=1 and 29,058 ML in t=19. In a broader context, these incremental shifts could also represent exogenous drivers of increasing demand for agricultural commodities, such as improved supply-chains and removal of import tariffs in overseas markets.

- *Doubled irrigation water demand* – The scaling parameter of the irrigation water demand function (γ) and corresponding choke volume (i_{CHOKE}) are doubled for each weather/season state and remain constant across all 20 periods. The risk in this case is misspecification of the fixed quotas in the first place such that there is always excess demand for water by irrigators.

Table 4.6 provides summary results for total benefits across the different risks and Figure 4.14 presents the distribution of differences between Scenario C and Scenario B across all simulations. Below I consider the results for each risk in more detail. The specific simulations discussed in each case are chosen to demonstrate the broader context of how and when price- or quantity-based water allocation may be more efficient.

	Average total benefits fixed irrigation quotas (Standard deviation)	Average total benefits irrigation water pricing (Standard deviation)	Average efficiency gains from water pricing (Percentage)
Basic model	$144.0 million ($6.1 million)	$144.6 million ($6.0 million)	$0.5 million (0.4%)
Climate change – Dry season inflows fall by 60% and wet season inflows fall by 25%	$1124 million ($4.1 million)	$113.6 million ($4.0 million)	$1.25 million (1.1%)
Price spike – High electricity price level increases from $67.71 to $102.31	$150.3 million ($10.0 million)	$150.6 million ($10.9 million)	$0.25 million (0.2%)
Energy policy change – Renewable Energy Certificate revenue ends at t =10	$137.4 million ($5.4 million)	$139.1 million ($5.2 million)	$1.7 million (1.2%)
Energy policy change – Renewable Energy Certificate revenue begins at t =10	$134.9 million ($5.6 million)	$135.8 million ($5.3 million)	$0.8 million (0.6%)
Price trend - Renewable Energy Certificate price grows at 3.5% per period	$149.7 million ($6.8 million)	$150.3 million ($7.0 million)	$0.6 million (0.4%)
Price trend - Renewable Energy Certificate price falls at 3.5% per period	$140.3 million ($5.7 million)	$141.1 million ($5.5 million)	$0.9 million (0.6%)
Increasing irrigation water demand – Scaling parameters (γ) and choke volumes increase by 3.5% per period	$162.9 million ($5.7 million)	$169.5 million ($5.5 million)	$6.7 million (4.1%)
Doubled irrigation water demand - Scaling parameters (γ) and choke volumes doubled	$186.2 million ($6.1 million)	$207.2 million ($4.8 million)	$21 million (11.3%)

Table 4.6. Comparison of total benefits under water pricing and fixed quotas for various risks.

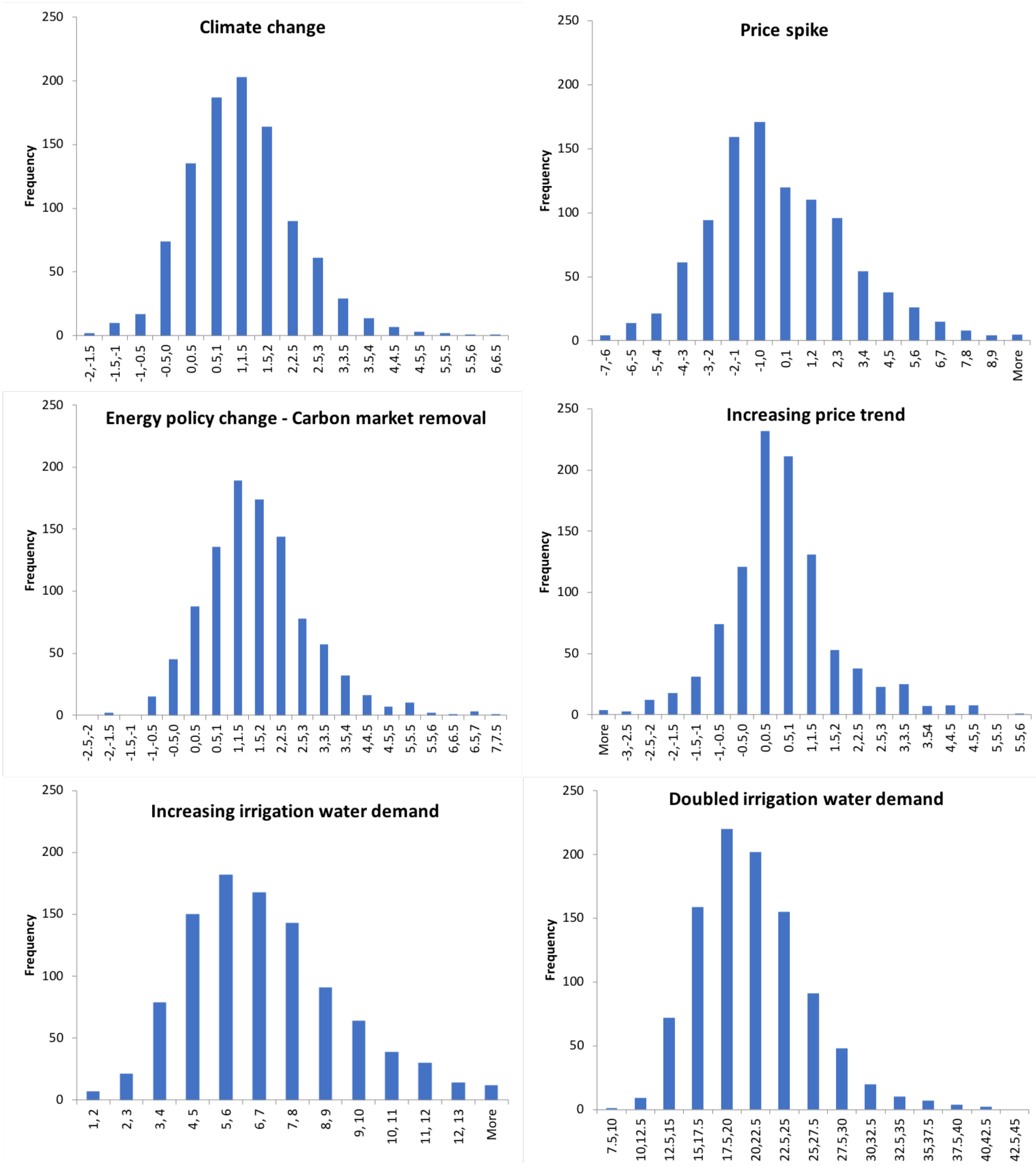

Figure 4.14. Histograms of difference in total benefits between Model C and Model B under risks. Benefits are stated in \$ million units. Positive values indicate total benefits with pricing > total benefits with quotas. 1000 simulations are conducted for each risk.

4.4.2.1. Climate Change

Compared to the results for the basic stochastic model reported in Section 4.4.1, average annual inflows are 34% lower under projected climate change. Irrigation extractions remain the same for both Scenario B and C because irrigators can access the buffer storage below S_{RISK}. The burden of reduced water availability falls on electricity generation, with hydropower extractions more than halving for both water allocation instruments. However, the average efficiency gains from water pricing are higher than under the basic model (Table 4.7). Figure 4.15 presents results from a simulation where the overall benefits of Scenario C exceed Scenario B by $2.5 million, or 2.2% of Model B total benefits. Reduced inflows mean that there is limited storage available for hydropower scheduling at the beginning of each summer season after the evaporation losses, environmental flows, and irrigation extractions (Figure 4.15a). Under water pricing, however, decreased irrigation extractions during wet and or high price periods enable the transfer of water from irrigation to hydropower. Similar to the simulation presented in Figure 4.13, the 'stickiness' of higher electricity prices (Figure 4.15c) ensures that these water reallocations are efficient overall.

	Average hydropower extractions GL (Standard deviation)	Average hydropower benefits $ millions (Standard deviation)	Average irrigation extractions GL (Standard deviation)	Average irrigation benefits $ millions (Standard deviation)	Average total extractions GL (Standard deviation)	Average total net benefits $ millions (Standard deviation)
Climate change – Dry season inflows fall by 60% and wet season inflows fall by 25%						
(B) Fixed quotas	192.3 (45.3)	$22.6 ($5.4)	300.1 (0)	$89.8 ($2.7)	492.3 (45.3)	$112.4 ($4.1)
(C) Water pricing	204.3 (54.3)	$55.6 ($5.7)	294.3 (18.63)	$58.0 ($3.1)	498.6 (43.7)	$113.6 ($4.0)

Table 4.7. Aggregate benefits and water extractions for fixed quotas and water pricing under reductions in inflows due to projected climate change. Averages reported for 1000 simulations. Each simulation experiences the same stochastic variations across periods as the corresponding simulation in a different scenario. The simulations span 20 seasons (10 years).

Figure 4.15. Key results under climate change: Time series of Model C (Water pricing) and Model B (Fixed quotas) extractions and reservoir levels for a selected simulation. The inflows, weather state, and electricity price state are the same for Model B and C in each time period.

4.4.2.2. Electricity Prices and Energy Policy

High Price Spike

The risk of high price spikes does not lead to any substantial change in the relative efficiency of pricing and quotas. On average, however, more water is transferred from irrigation to hydropower as irrigators cutback their demand more when electricity prices are higher. The aggregate result is ambiguous from an efficiency perspective. Notably, the relative benefits of pricing over quotas, or vice versa, across different simulations become more distributed (see Figure 4.14). Compared to the distribution of simulations for basic model (Figure 4.12), there are more occasions where water pricing generates substantial efficiency gains or losses in excess of $2 million and above. Once again, the transition of electricity prices is an important determinant of where water reallocation is efficient. Figure 4.16 presents a simulation where fixed quotas generate relative efficiency gains of $4.2 million because the benefits generated by increased hydropower extractions (30 GL) are outweighed by the benefits lost from reduced irrigation extractions (61 GL). One-period price spikes in t=3 and t=13 (Figure 4.16b) cause major contractions in irrigation extractions (Figure 4.17d) that lead to increased hydropower extractions in t=4 and t=15 (Figure 4.16c) when electricity prices are very low (Figure 4.16b).

	Average hydropower extractions GL (Standard deviation)	Average NPV hydropower benefits $ millions (Standard deviation)	Average irrigation extractions GL (Standard deviation)	Average NPV of irrigation benefits $ millions (Standard deviation)	Average total extractions GL (Standard deviation)	Average NPV total net benefits $ millions (Standard deviation)
Price spike – High electricity price level increases from $67.71 to $102.31						
(B) Fixed quotas	459.3 (57.3)	$60.6 ($11.3)	300.1 (0)	$89.8 ($2.7)	759.4 (57.3)	$150.3 ($10.0)
(C) Water pricing	458.3 (69.0)	$95.2 ($14.0)	281.7 (23.0)	$55.4 ($3.9)	740.0 (58.2)	$150.6 ($10.9)

Table 4.8. Aggregate benefits and water extractions for fixed quotas and water pricing in the presence of price spikes. Averages reported for 1000 simulations. Each simulation experiences the same stochastic variations across periods as the corresponding simulation in a different scenario. The simulations span 20 seasons (10 years).

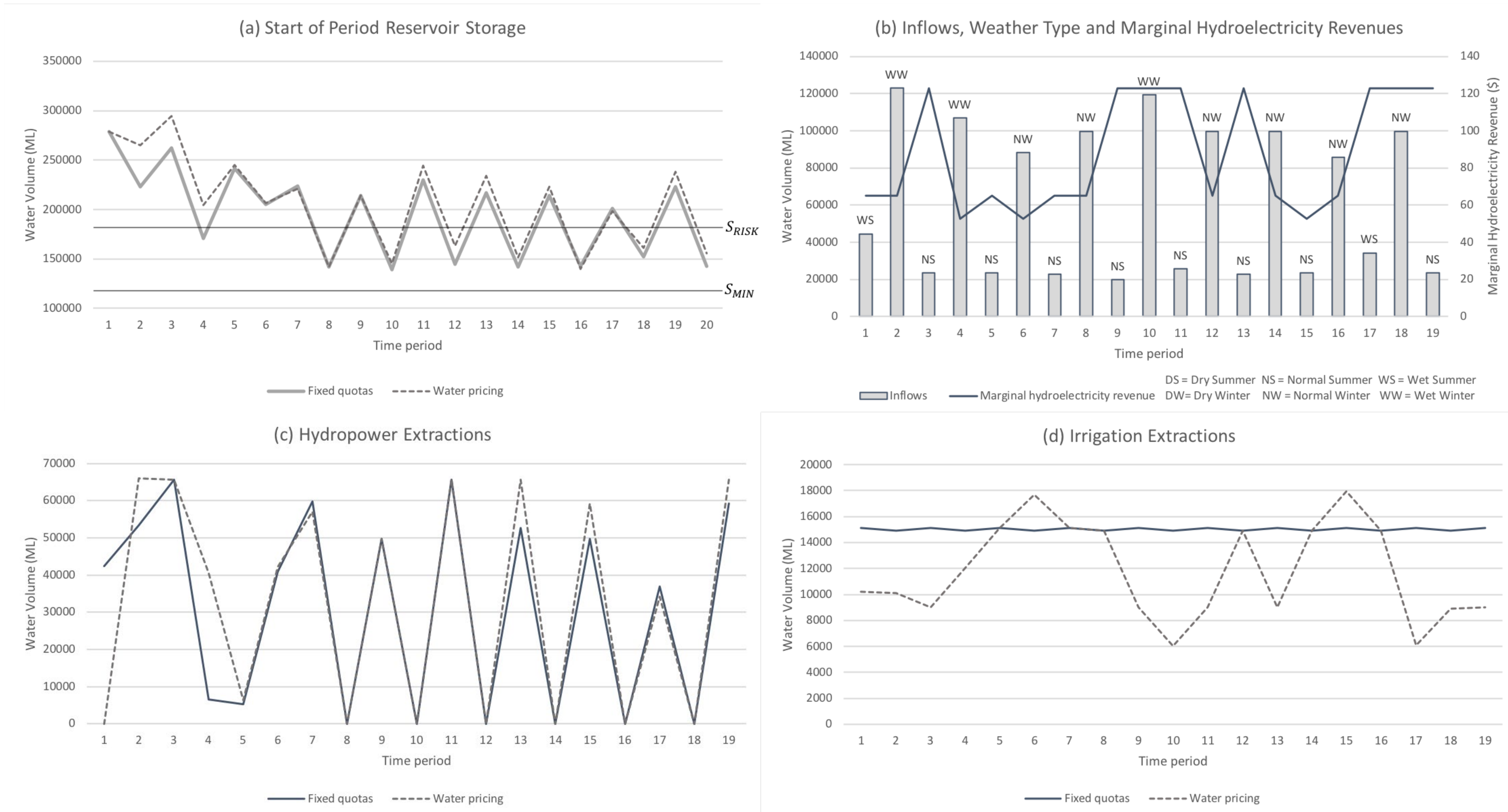

Figure 4.16. Key results under high price spike: Time series of Model C (Water pricing) and Model B (Fixed quotas) extractions and reservoir levels for a selected simulation. The inflows, weather state, and electricity price state are the same for Model B and C in each time period.

Energy Policy Change & Price Trends

The removal or addition of the carbon market has level effects on marginal hydroelectricity revenues and, hence, the water price. In the case of removal, water pricing enables the transfer of more water to irrigation from t=10 onwards. On the other hand, the addition of the carbon market t=10 means that more water is transferred to electricity generation in later periods. For both cases, pricing generates efficiency gains relative to quotas. The aggregate benefits remain small, albeit more substantial in the case of market removal compared to the basic model. Similarly, water pricing allocates water more efficiently under both increasing and decreasing price trends. More water is extracted for hydropower (irrigation) as the water price steadily rises (falls). Figure 4.17 demonstrates how the electricity price and, hence, irrigation extractions change for corresponding simulations under carbon market removal and an increasing price trend.

	Average hydropower extractions GL (Standard deviation)	Average NPV hydropower benefits $ millions (Standard deviation)	Average irrigation extractions GL (Standard deviation)	Average NPV of irrigation benefits $ millions (Standard deviation)	Average total extractions GL (Standard deviation)	Average NPV total net benefits $ millions (Standard deviation)
Energy policy change – Renewable Energy Certificate revenue ends at t=10						
(B) Fixed quotas	469.1 (60.3)	$47.7 ($6.9)	300.1 (0)	$89.75 ($2.7)	769.2 (60.3)	$137.4 ($5.4)
(C) Water pricing	437.4 (74.8)	$75.8 ($7.6)	349.7 (26.52)	$63.3 ($3.5)	787.1 (60.1)	$139.1 ($5.2)
Energy policy change – Renewable Energy Certificate revenue begins at t=10						
(B) Fixed quotas	448.9 (58.1)	$45.2 ($7.1)	300.1 (0)	$89.8 ($2.7)	749.0 (58.1)	$134.9 ($5.6)
(C) Water pricing	416.0 (72.7)	$71.7 ($7.9)	348.8 (25.5)	$64.1 ($3.6)	764.8 (57.2)	$135.8 ($5.3)
Price trend - Renewable Energy Certificate price grows at 3.5% per period						
(B) Fixed quotas	473.0 (59.9)	$60.0 ($8.5)	300.1 (0)	$89.8 ($2.7)	773.1 (59.9)	$149.7 ($6.8)
(C) Water pricing	491.1 (68.6)	$95.9 ($9.2)	267.9 (16.0)	$54.5 ($2.9)	759.3 (58.7)	$150.3 ($7.0)
Price trend - Renewable Energy Certificate price decreases by 3.5% per period						
(B) Fixed quotas	474.9 (60.9)	$50.5 ($7.2)	300.1 (0)	$89.8 ($2.7)	775.0 (60.9)	$140.3 ($5.7)
(C) Water pricing	460.8 (73.3)	$80.6 ($7.9)	317.1 (2.1)	$60.6 ($3.3)	778.0 (60.8)	$141.1 ($5.5)

Table 4.9. Aggregate benefits and water extractions for fixed quotas and water pricing under energy policy changes and price trends. Averages reported for 1000 simulations.

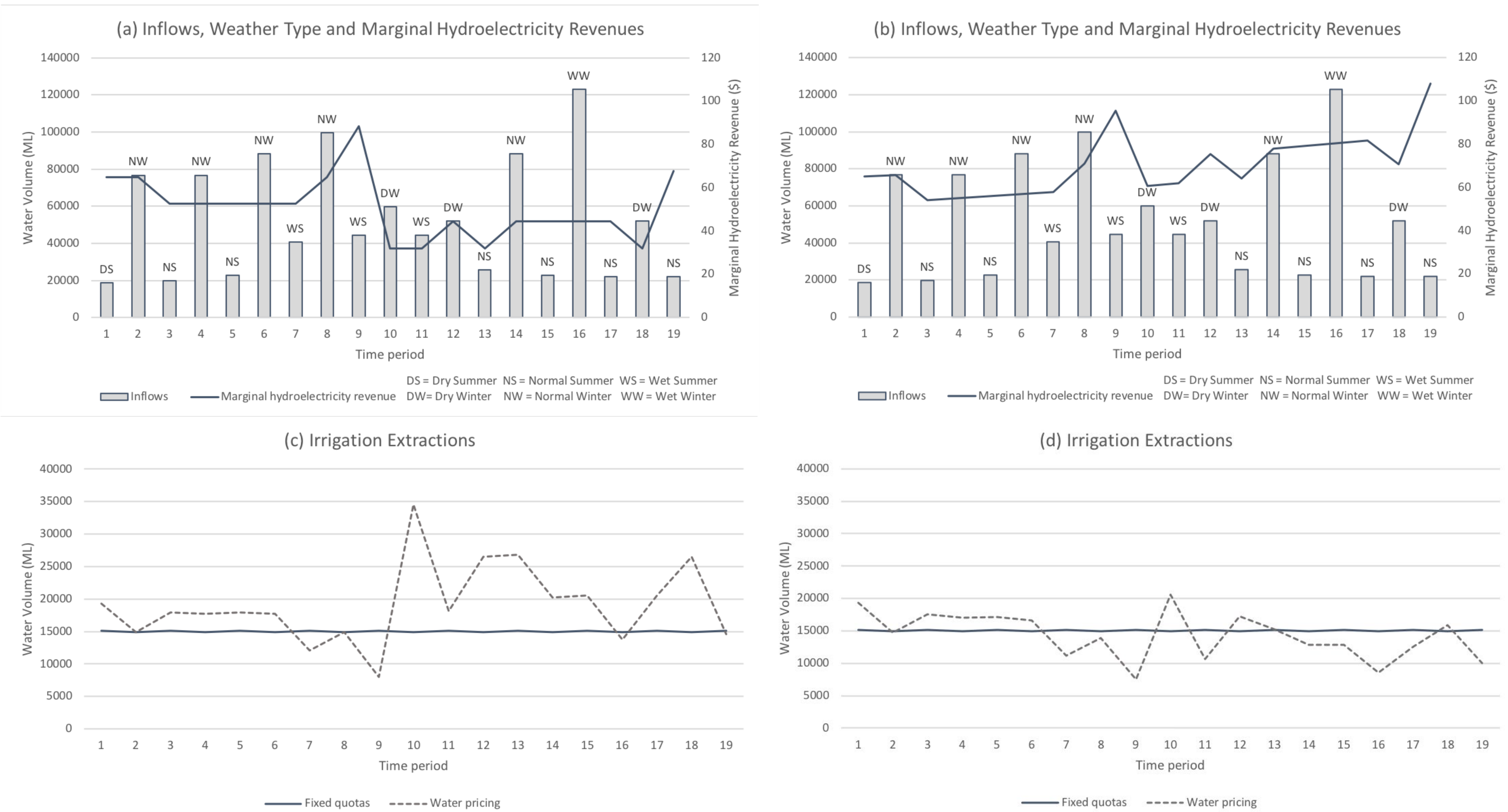

Figure 4.17. Marginal hydroelectricity revenues and irrigation extractions under carbon market removal and an increasing price trend. (a) Marginal hydroelectricity revenues and (c) irrigation extractions under carbon market removal. (b) Marginal hydroelectricity revenues and (d) irrigation extractions under an increasing price trend. Results reported for the same simulation (i.e. time-path of state variables is identical).

4.4.2.3. Increasing and Doubled Irrigation Water Demand

These risks demonstrate how fixed quotas can lead to inefficient water allocation over time. In the case of increasing water demand, there are substantial benefits from water pricing being able to gradually allocate more water away from hydropower to irrigation. The benefits are even larger for the case where irrigation water demand is doubled and stays the same over time; this represents a situation where fixed quotas have been determined poorly and there is excess irrigation water demand from the outset. Figure 4.18 shows the time series of hydropower and irrigation extractions for the same simulation of the weather and electricity price transition. In the case of a gradual increase in water demand, summer hydropower extractions are lower, but it is only in the final year that they almost cease. On the other hand, if irrigation water demand is doubled then water pricing entails that the main purpose of the reservoir becomes irrigation extractions. Note that this does not mean that the hydropower operator becomes less profitable; on the contrary, it is just that irrigation water supply becomes the main source of revenue. By comparison, under the original specification for irrigation water demand in Section 4.4.1 the hydropower operator generates average profits of $86.6 million under water pricing from 480.8 GL of hydropower extractions. If fixed quotas are misspecified or not adjusted to changing irrigation water demand, water pricing enables the hydropower operator to capture higher profits whilst producing less electricity.

	Average hydropower extractions GL (Standard deviation)	Average hydropower benefits $ millions (Standard deviation)	Average irrigation extractions GL (Standard deviation)	Average irrigation benefits $ millions (Standard deviation)	Average total extractions GL (Standard deviation)	Average total net benefits $ millions (Standard deviation)
Increasing irrigation water demand – Scaling parameters (γ) and choke volumes increase by 3.5% per period						
(B) Fixed quotas	474.6 (60.7)	$54.3 ($7.7)	300.1 (0)	$100.9 ($2.9)	774.7 (60.7)	$162.9 ($5.7)
(C) Water pricing	389.5 (76.97)	$88.9 ($8.3)	416.4 (27.3)	$80.6 ($4.5)	805.8 (60.6)	$169.5 ($5.5)
Doubled irrigation water demand - Scaling parameters (γ) and corresponding choke volumes doubled						
(B) Fixed quotas	474.6 (60.7)	$54.3 ($7.7)	300.1 (0)	$132.0 ($2.8)	774.7 (60.7)	$186.2 ($6.1)
(C) Water pricing	242.0 (79.6)	$91.3 ($7.7)	588.6 (37.3)	$116.0 ($6.3)	830.6 (57.1)	$207.2 ($4.8)

Table 4.10. Aggregate benefits and water extractions for fixed quotas and water pricing under increasing and doubled irrigation water demand. Averages reported for 1000 simulations.

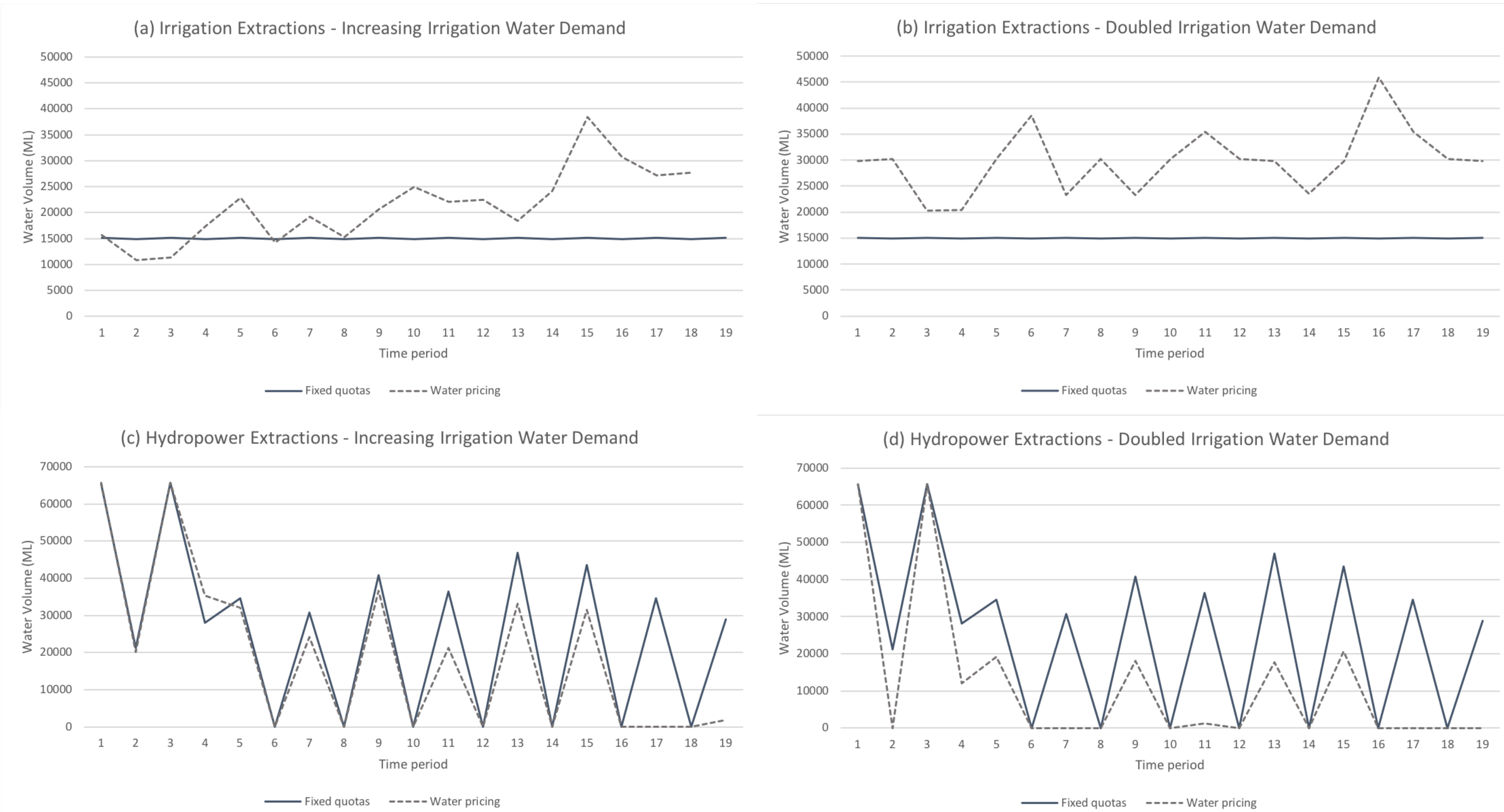

Figure 4.18. Irrigation and hydropower extractions for increasing and doubled irrigation water demand risk scenarios. Time series of Model C (Water pricing) and Model B (Fixed quotas) extractions for the same simulation of inflows, weather states, and electricity price states.

4.4.2.4 Multiple Risks

Table 4.11. shows that the presence of multiple risks can either amplify or dampen any efficiency gains from water pricing. For example, the sum of gains under climate change ($1.3 million) and increasing irrigation water demand ($6.7 million) alone are less than gains if both risks are present ($11.8 million). On the other hand, the presence of price spikes dampens efficiency gains under increasing irrigation water demand and climate change.

	Average hydropower extractions GL	Average hydropower benefits $ millions	Average irrigation extractions GL	Average irrigation benefits $ millions	Average total extractions GL	Average total benefits $ millions	Efficiency gains from water pricing $ millions (%)
Climate change & Energy policy change (Carbon market removal)							**$3.6 (3.3%)**
(B) Fixed quotas	192.3	$21.1	300.1	$89.8	494.3	$110.8	
(C) Water pricing	177.7	$51.1	349.7	$63.3	527.4	$114.4	
Climate change & Increasing price trend							**$0.5 (0.4%)**
(B) Fixed quotas	192.3	$24.1	300.1	$89.8	494.3	$113.8	
(C) Water pricing	218.4	$59.8	267.9	$54.5	486.3	$114.3	
Climate change & Price spike							**$0.4 (0.3%)**
(B) Fixed quotas	189.5	$25.1	300.1	$89.8	489.6	$114.9	
(C) Water pricing	206.0	$59.9	281.7	$55.4	487.7	$115.2	
Climate change & Increasing irrigation water demand							**$11.8 (9.0%)**
(B) Fixed quotas	192.3	$22.6	300.1	$108.6	492.3	$131.2	
(C) Water pricing	151.7	$62.4	416.4	$80.6	568.1	$143.0	
Increasing irrigation water demand & Energy policy change (Carbon market removal in ***t***=10)							**$54.6 (35.0%)**
(B) Fixed quotas	469.1	$47.7	300.1	$108.6	769.2	$156.3	
(C) Water pricing	334.4	$79.2	508.0	$131.7	842.4	$172.8	
Increasing irrigation water demand & Increasing price trend							**$4.2 (2.5%)**
(B) Fixed quotas	473.0	$60.0	300.1	$108.6	773.1	$168.6	
(C) Water pricing	418.5	$97.8	373.9	$75.0	792.4	$172.8	
Increasing irrigation water demand & Price spike							**$4.6 (2.7%)**
(B) Fixed quotas	459.3	$60.6	300.1	$108.6	759.4	$169.1	
(C) Water pricing	392.1	$96.9	398.1	$76.9	790.2	$173.8	

Table 4.11. Aggregate benefits and water extractions for fixed quotas and water pricing under multiple risks.

4.4.3. Sensitivity Analysis

4.4.3.1. Price Elasticity of Demand

The price elasticity of demand (α) defines the slope of the marginal benefit function for irrigation water demand. The value used above ($\alpha =$ -0.81) implies that the demand for water decreases by 0.81% for every 1% increase in price. A lower value (i.e. $\alpha <$ -0.81) indicates the marginal benefit function has a flatter slope and lower choke water volume for a given weather/season state. Conversely, a higher value (i.e. $\alpha >$ -0.81) indicates a steeper slope and higher choke volume. Changes to α affect the size of additional benefits from higher irrigation extractions (Figure 4.6), relative efficiency gains or losses from transferring water from irrigation to hydropower (Figures 4.7-4.10), and the volume of irrigation extractions under pricing for a given weather/season state and electricity price level (Figure 4.12). Table 4.12 demonstrates net effects for the basic model and selected risks: efficiency gains from water pricing are reduced (increased) for lower (higher) values of α, except for climate change and carbon market removal.

	Average hydropower benefits ($ millions)			Average irrigation benefits ($ millions)			Average total benefits ($ millions)		
	Model B	Model C	*Model C - Model B*	Model B	Model C	*Model C - Model B*	Model B	Model C	**Model C - Model B**
Basic model									
α= -0.81	54.3	86.6	*32.3*	89.8	58.0	*-31.8*	144.0	144.6	**$0.5**
α= -0.9	54.3	86.5	*32.2*	85.6	53.8	*-31.8*	139.9	140.0	**$0.2**
α= -0.7	54.3	86.7	*32.4*	95.4	63.7	*-31.7*	149.7	150.4	**$0.7**
α= -0.5	54.3	86.9	*32.6*	107.6	76.1	*-31.4*	161.9	163.0	**$1.1**
Price spike									
α= -0.81	60.6	95.2	*34.6*	89.8	55.4	*-34.4*	150.3	150.6	**$0.3**
α= -0.9	60.6	95.1	*34.5*	85.6	51.3	*-34.3*	146.2	146.4	**$0.2**
α= -0.7	60.6	95.5	*34.9*	95.4	61.0	*-34.4*	156.0	156.5	**$0.5**
α= -0.5	60.6	96.0	*35.4*	107.6	73.1	*-34.4*	168.2	169.1	**$1.0**
Increasing irrigation water demand									
α= -0.81	54.3	88.9	*34.6*	89.8	55.4	*-34.4*	162.9	169.5	**$6.7**
α= -0.9	54.3	88.8	*35.3*	103.3	74.8	*-28.5*	157.6	163.6	**$6.0**
α= -0.7	54.3	89.0	*34.7*	115.6	88.6	*-27.0*	169.9	177.6	**$7.7**
α= -0.5	54.3	89.2	*34.9*	129.3	105.9	*-23.4*	183.6	195.1	**$11.5**
Climate change & Energy policy change (Carbon market removal in t=10)									
α= -0.81	21.1	51.1	*30.0*	89.8	63.3	*-26.5*	110.8	114.4	**$3.6**
α= -0.9	21.1	51.4	*30.3*	85.6	59.2	*-26.4*	106.7	110.6	**$3.9**
α= -0.7	21.1	50.8	*29.8*	95.4	68.9	*-26.5*	116.5	119.8	**$3.3**
α= -0.5	21.1	50.5	*29.4*	107.6	81.1	*-26.4*	128.4	131.6	**$3.3**

Table 4.12. Sensitivity analysis of average benefits to the price elasticity of demand.

4.4.3.2. Weather-Based Shifts in Water Demand

An additional driver of the results are the scaling parameters of the water demand function (γ). These parameters determine the distance between the irrigation water demand functions for a given season and, therefore, the variation in irrigation extractions between, say, a normal and dry summer season under the same water price. In terms of the two different water allocation instruments, the γ parameters determine how closely fixed quotas approximate water pricing under variable weather. To demonstrate the outcomes with regards to efficiency, I consider two alternative specifications of gamma. The first doubles the gap between the normal and dry weather marginal benefit functions for both seasons (see Appendix 4.A5 for full details of the original derivation of parameters). In practice, this involves a rightward shift of the marginal benefit function for dry weather in Figure 4.12 and means that, for example, the irrigator will extract 23,474 ML in a dry summer under a medium electricity price level. This is 4,180 ML more than dry summer extractions under the original specification and, in turn, a further 4,180ML higher than normal summer extractions in all cases (including fixed quotas). The choke volume is also doubled for dry summers and dry winters. The second specification considers the inverse case: the contraction of the water demand function in wet weather is doubled, or a leftward shift of the wet weather marginal benefit function. Formally, the values of γ and i_{CHOKE} for the first alternative are:

$$\gamma = \begin{Bmatrix} \gamma_{\phi=1,d} & \gamma_{\phi=1,n} & \gamma_{\phi=1,w} \\ \gamma_{\phi=2,d} & \gamma_{\phi=2,n} & \gamma_{\phi=2,w} \end{Bmatrix} = \begin{Bmatrix} 1158829 & 746125 & 503291 \\ 1184746 & 735314 & 500033 \end{Bmatrix}$$

$$\tilde{\imath}_{CHOKE} = \begin{Bmatrix} \tilde{\imath}_{CHOKE_{\phi=1,d}} & \tilde{\imath}_{CHOKE_{\phi=1,n}} & \tilde{\imath}_{CHOKE_{\phi=1,w}} \\ \tilde{\imath}_{CHOKE_{\phi=2,d}} & \tilde{\imath}_{CHOKE_{\phi=2,n}} & \tilde{\imath}_{CHOKE_{\phi=2,w}} \end{Bmatrix} = \begin{Bmatrix} 6417\text{ ML} & 4131\text{ ML} & 2787\text{ ML} \\ 6560\text{ ML} & 4072\text{ ML} & 2769\text{ ML} \end{Bmatrix}$$

and as follows for the enhanced contraction of wet weather water demand:

$$\gamma = \begin{Bmatrix} \gamma_{\phi=1,d} & \gamma_{\phi=1,n} & \gamma_{\phi=1,w} \\ \gamma_{\phi=2,d} & \gamma_{\phi=2,n} & \gamma_{\phi=2,w} \end{Bmatrix} = \begin{Bmatrix} 952477 & 746125 & 260458 \\ 960030 & 735314 & 264752 \end{Bmatrix}$$

$$\tilde{\imath}_{CHOKE} = \begin{Bmatrix} \tilde{\imath}_{CHOKE_{\phi=1,d}} & \tilde{\imath}_{CHOKE_{\phi=1,n}} & \tilde{\imath}_{CHOKE_{\phi=1,w}} \\ \tilde{\imath}_{CHOKE_{\phi=2,d}} & \tilde{\imath}_{CHOKE_{\phi=2,n}} & \tilde{\imath}_{CHOKE_{\phi=2,w}} \end{Bmatrix} = \begin{Bmatrix} 5274\text{ ML} & 4131\text{ ML} & 1442\text{ ML} \\ 5316\text{ ML} & 4072\text{ ML} & 1466\text{ ML} \end{Bmatrix}$$

Table 4.13 presents the outcomes in terms of average water extractions, benefits, and efficiency gains from water pricing for the basic model and selected risks considered in Section 4.3.2. For the alternative specification of dry weather water demand, irrigation (hydropower) extractions under water pricing are higher (lower) than under the original. Conversely, a leftward shift of wet weather water demand results in irrigation (hydropower) extractions under water pricing to be lower (higher) compared to the original. For both changes to the water demand function the efficiency gains under water pricing are higher. This indicates that the further away that fixed quotas are from the (within-period) level of efficient water extractions (i.e. the volume under water pricing that matches the marginal cost and marginal benefit of irrigation water), then the greater the average efficiency gains from water pricing.

4.4.3.3. Electricity Price Transition

The electricity price transition can also influence the results. This was highlighted in the presentation of specific simulations in Sections 4.4.1-4.4.2 and the discussion of relative efficiency gains in Section 4.2.7. Here, I consider an alternative specification of the electricity price transition such that: (i) the probability of successive high electricity price levels is higher (increasing from 0.43 to 0.60), (ii) the movement from a high to low electricity price level is no longer possible (decreasing from 0.14 to 0), and (iii) the probability of moving from a high to medium price level is slightly reduced (decreasing from 0.43 to 0.40). Formally, the electricity price transition is now described by the following transition matrix (with the changes highlighted in bold):

		L_t		
		l	m	h
L_{t+1}	l	0.5	0.17	0
	m	0.5	0.55	0.4
	h	0	0.28	0.60

Table 4.14 presents the outcomes in terms of average water extractions, benefits, and efficiency gains from water pricing for the basic model and selected risks. Across the 20,000 time periods simulated, the percentage of high electricity price states rises relative to the original electricity price transition (from 24.5% to 32.2%), the number of low-price periods declines (from 22.5% to 15.9%), and proportion of medium price states increases slightly (51.9% to 53.0%). With more 'sticky' high electricity prices, the efficiency gains from water pricing only rise by a modest amount under the basic model and price spikes. On average, however, there is a substantial transfer of water from irrigation to hydropower. Further, the standard deviation of benefits under the price spike are substantially higher, indicating a larger distribution of efficiency gains/losses compared to the histogram in Figure 4.15 and more outcomes where the relative efficiency gains of pricing or quotas are large. In terms of the other risks, efficiency gains from water pricing are reduced on aggregate but the standard deviation is slightly higher; this is due to the original efficiency gains under these risks largely arising from higher irrigation extractions and farmer profits under water pricing.

	Average hydropower extractions GL	Average hydropower benefits $ millions	Average irrigation extractions GL	Average irrigation benefits $ millions	Average total extractions GL	Average total benefits $ millions	Efficiency gains from water pricing $ millions (%)
Basic model							**$0.5 (0.4%)**
Fixed quotas	474.6	$54.3	300.1	$89.8	774.7	$144.0	
Water pricing	480.8	$86.6	294.3	$58.0	775.1	$144.6	
Basic model – Doubled high shift							**$1.6 (1.1%)**
Fixed quotas	474.6	$54.3	300.1	$92.6	774.7	$146.9	
Water pricing	464.0	$86.8	313.6	$61.7	777.6	$148.5	
Basic model – Doubled low shift							**$2.1 (1.5%)**
Fixed quotas	474.6	$54.3	300.1	$83.6	774.7	$137.9	
Water pricing	497.3	$86.3	272.4	$53.7	769.7	$140.0	
Price spike							**$0.3 (0.2%)**
Fixed quotas	459.3	$60.6	300.1	$89.8	759.4	$150.3	
Water pricing	458.3	$95.2	281.7	$55.4	740.0	$150.6	
Price spike – Doubled high shift							**$1.1 (0.7%)**
Fixed quotas	459.3	$60.6	300.1	$92.6	759.4	$153.2	
Water pricing	453.9	$95.4	300.1	$59.0	754.0	$154.3	
Price spike – Doubled low shift							**$2.1 (1.5%)**
Fixed quotas	459.3	$60.6	300.1	$83.6	759.4	$144.2	
Water pricing	472.2	$95.0	260.8	$51.3	733.0	$146.3	
Climate change & Energy policy change (Carbon market removal in t=10)							**$3.6 (3.3%)**
Fixed quotas	192.3	$21.1	300.1	$89.8	494.3	$110.8	
Water pricing	177.7	$51.1	349.7	$63.3	527.4	$114.4	
Climate change & Energy policy change (Carbon market removal in t=10)– Doubled high shift							**$6.1 (5.3%)**
Fixed quotas	192.3	$21.1	300.1	$92.6	492.3	$113.7	
Water pricing	169.7	$52.3	372.9	$67.4	542.6	$119.7	
Climate change & Energy policy change (Carbon market removal in t=10) – Doubled low shift							**$4.3 (4.1%)**
Fixed quotas	192.3	$21.1	300.1	$83.6	492.3	$104.7	
Water pricing	194.6	$50.4	323.5	$58.6	518.1	$109.0	

Table 4.13. Sensitivity analysis of average benefits and water extractions to specification of the water demand function for different weather/season states.

	Average hydropower extractions GL	Average hydropower benefits $ millions (Standard deviation)	Average irrigation extractions GL	Average irrigation benefits $ millions (Standard deviation)	Average total extractions GL	Average total benefits $ millions (Standard deviation)	Efficiency gains from water pricing $ millions (%)
Basic model							**$0.5 (0.4%)**
(B) Fixed quotas	474.6	$54.3 ($7.7)	300.1	$89.8 ($2.7)	774.7	$144.0 ($6.1)	
(C) Water pricing	480.8	$86.6 ($8.4)	294.3	$58.0 ($3.1)	775.1	$144.6 ($6.0)	
Basic model – Increased 'stickiness' of high electricity price level							**$0.9 (0.6%)**
(B) Fixed quotas	475.9	$56.1 ($8.3)	300.1	$89.8 ($2.7)	776.0	$145.6 ($6.7)	
(C) Water pricing	490.3	$89.6 ($9.2)	286.0	$56.9 ($3.3)	776.3	$146.4 ($6.6)	
Price spike							**$0.3 (0.2%)**
(B) Fixed quotas	459.3	$60.6 ($11.3)	300.1	$89.8 ($2.7)	759.4	$150.3 ($10.0)	
(C) Water pricing	458.31	$95.2 ($14.0)	281.7	$55.4 ($3.9)	740.0	$150.6 ($10.9)	
Price spike – Increased 'stickiness' of high electricity price level							**$0.8 (0.5%)**
(B) Fixed quotas	447.5	$64.4 ($13.6)	300.1	$89.8 ($2.7)	747.6	$154.1 ($12.6)	
(C) Water pricing	466.3	$101.5 ($17.0)	269.3	$53.5 ($4.6)	735.6	$155.0 ($13.1)	
Increasing irrigation water demand							**$6.7 (4.1%)**
(B) Fixed quotas	474.6	$54.3 ($7.7)	300.1	$100.9 ($2.9)	774.7	$162.9 ($5.7)	
(C) Water pricing	389.5	$88.9 ($8.3)	416.4	$80.6 ($4.5)	805.8	$169.5 ($5.6)	
Increasing irrigation water demand – Increased 'stickiness' of high electricity price level							**$6.1 (3.7%)**
(B) Fixed quotas	475.9	$56.1 ($8.3)	300.1	$108.6 ($2.9)	776.0	$164.7 ($6.6)	
(C) Water pricing	400.0	$91.8 ($9.2)	403.8	$79.0 ($4.7)	803.8	$170.8 ($6.0)	
Climate change & Energy policy change (Carbon market removal in t=10)							**$3.6 (3.3%)**
(B) Fixed quotas	192.3	$21.1 ($4.7)	300.1	$89.8 ($2.7)	494.3	$110.8 ($3.6)	
(C) Water pricing	177.7	$51.1 ($4.7)	349.7	$63.3 ($3.5)	527.4	$114.4 ($3.7)	
Climate change & Energy policy change (Carbon market removal in t=10) – Increased 'stickiness' of high electricity price level							**$3.1 (2.8%)**
(B) Fixed quotas	192.3	$21.6 ($5.0)	300.1	$89.8 ($2.7)	492.3	$111.3 ($3.8)	
(C) Water pricing	184.9	$52.5 ($5.3)	336.3	$62.0 ($3.7)	521.2	$114.4 ($3.9)	

Table 4.14. Sensitivity analysis of the specification of electricity price transition.

4.5. Discussion

This section discusses the policy implications of the modelling results in Section 4.4. The focus is on the broader regulation of multipurpose hydropower reservoirs rather than the location that the model is calibrated to. The discussion is framed by six key insights.

(i) *Quotas can provide a suitable approximation to efficient water allocation if they can be appropriately (re)calibrated and there is limited variation in the demand for water services*

All approaches to regulating water allocation will involve some implementation costs. For example, measuring deliveries, monitoring payments or operation decisions, and enforcing penalties for infractions. In the above modelling, I have not incorporated transaction costs associated with water pricing. In cases where there are multiple offtakes from a reservoir to provide water services, transaction costs may become high for the hydropower operator, regulator, and water consumers. By contrast, the relative efficiency gains from water pricing in this model are modest when quotas are calibrated to the water price prevailing under normal weather and medium electricity prices. Quotas may be simpler to implement than pricing and provide a suitable approximation if they can be regularly updated and there is sufficient information available regarding the demand for water services. Further, quotas may suffice when the demand for water services is not growing markedly or does not vary substantially with changes in weather or market prices.

(ii) *Water pricing provides greater flexibility to reallocate water efficiently under variability in the demand for water services, imperfect information, water supply scarcity, and structural changes to energy policies and markets*

In practice, there are often many barriers to efficiently re-allocating water through command-and-control, quantity-based regulation (Grafton et al. 2017; Marston & Cai 2016). In the case of hydropower regulation, prominent barriers include lack of information (e.g. estimating irrigation water demand across different farmers) and vested interests (e.g. an increased irrigation water quota being a direct opportunity cost to the hydropower operator, or quotas being determined through political negotiations rather than economic calculations). These barriers are why hydropower re-licensing processes can take many years and typically stipulate operation regulations spanning several decades (see Kosnik 2013; Tonka 2015; Viers 2011). In this Chapter, I find that that water pricing can, on average, allocate water more efficiently over a ten-year planning horizon for the following risks: water scarcity, increasing irrigation water demand, and level shifts in the value of hydroelectricity generation under energy policy reforms. Although the absolute value of the efficiency gains for our modelling of a single reservoir may appear modest in some of these cases, a 1-2% increase in the efficiency of multipurpose reservoir operations would represent substantial economic benefits for a jurisdiction containing many such reservoirs.

(iii) *Instrument design is an important consideration for water pricing; further efficiency gains could be obtained by incorporating intertemporal opportunity costs into irrigator's decision-making*

I have also shown in this Chapter how the application of volumetric water pricing under uncertainty can cause inefficient water allocation. In the model, a key source of dynamic inefficiency is the mismatch between the water price determining irrigation extractions in period t and the actual opportunity cost of foregone generation in period $t+1$ if the electricity price level changes. Given that irrigators will prefer *ex ante* water prices to inform cropping decisions for a given season and hydropower companies sell electricity outside of spot markets, this is a reasonable representation of how water pricing could be structured if it were more widely applied to multipurpose hydropower regulation. In practice, therefore, expectations of the opportunity cost of water services (i.e. future hydroelectricity revenues) may need to be incorporated into the water price. Weather expectations may also be an important consideration. In this calibration of the model, these is no excess irrigation water demand for either quota- or pricing-based regulation. But if irrigation extractions could not occur, say, below S_{RISK}, then irrigation extractions in period t could detract from irrigation extractions in period $t+1$ when the weather may be dry and water demand higher. Water rationing imposes large costs and methods are available to incorporate intertemporal opportunity costs into water pricing (see Grafton et al. 2014; Griffin 2016; Moncur & Pollock 1988). Further research is required into how real-world applications of water pricing to multipurpose hydropower reservoirs should augment the simple, volumetric approach modelled here to address dynamic sources of inefficiency.

(iv) *There can be large discrepancies in the outcomes from pricing- and quota-based water allocation, and regulators also need to consider externalities when choosing policy instruments*

In this Chapter I have only modelled the direct benefits accruing to a hydropower operator and irrigators from water use. In reality, there may be significant economic benefits associated with other aspects of the model, such as the level of storage and the volume of environmental flows. For example, the benefits from recreational fishing or the non-market values associated with habitat for endangered native fish species. Further, both irrigation and hydroelectricity can generate positive externalities, such as rural employment in the former case and reduced air pollution in the latter. Hence, regulators have more objectives than maximising the average efficiency of water allocation when choosing planning instruments. Under projected climate change, for example, the average efficiency gains from water pricing may be less important than quotas maintaining higher storage levels and protecting a fishery in the reservoir (see Table 4.7). On the other hand, those efficiency gains from pricing may be amplified by higher hydroelectricity generation occurring under water pricing. The point is that the regulatory context is important and the efficiency of water allocation may be only one of several considerations.

(v) *For profit-motivated hydropower companies, water pricing is the preferred regulatory instrument for transitioning to multipurpose operations*

Section 4.4.1. showed how pricing water services can increase hydropower profits even if the price is set at the approximate opportunity cost of foregone electricity generation. This result partly reflects the model specification: irrigation extractions can occur below S_{RISK} and more water can be extracted from the reservoir than if it is operated for hydropower only. However, there is a more general insight here that is reinforced by fixed, free irrigation quotas requiring substantial foregone hydropower profits across the various risks modelled in Section 4.4. For hydropower companies operating existing single-purpose reservoirs, regulatory reforms that simply reallocate water to a new service represents a direct, win-lose trade-off that benefits only the users of those new water services. Pricing can remove operators' vested interest in maintaining single-purpose hydropower operations or providing the bare minimum of water services required by regulation. Further, the potential to generate irrigation revenues can provide greater flexibility to reallocate water as the value of energy and water services change. The water demand risks in Section 4.4.2.3. provided an example where, under irrigation water pricing, overall efficiency benefits can be consistent with higher hydropower operator profits even if electricity generation declines markedly under water reallocation. Further, obtaining private finance for multi-purpose reservoirs can be challenging without significant public co-financing arrangements (Naughton et al. 2017), and water pricing could support the potential benefits of multipurpose operations being realised in practice.

(vi) For profit-motivated irrigators, a fixed quantity of free water will always be preferred if the volume of deliveries is guaranteed and calibrated to variable water demand

The profits of irrigators are higher under quotas for all the aggregate results reported in Section 4. This is due to: (i) the quota being provided free of charge, (ii) irrigation extractions being guaranteed due to the storage buffer created by hydropower extractions being forbidden below S_{RISK}, and (iii) the quota being carefully calibrated so that there is a duality between price- and quantity-based irrigation water allocation under normal weather and medium electricity prices. In practice, none of these favourable conditions are necessarily guaranteed. Irrigators may be charged a fixed fee for their allocation and could prefer a dynamic volumetric price that provides the flexibility to access more or less water as their water demand changes. Storage may not be regulated to ensure that irrigation has priority under water scarcity and, in fact, a volumetric water price could be defined to provide a hydropower operator with an economic incentive to ensure that there is no excess irrigation water demand. Finally, quotas may be set at an inadequate initial level or not updated to reflect rising irrigation water demand such that the total cost of paying for water is outweighed by the foregone revenue from not being able to access enough of it. I have not modelled these scenarios in this study, but they deserve further research and, from a practical standpoint, consideration for real-world applications.

6. Conclusion

This study has examined the efficiency of multipurpose hydropower regulation under price- and quantity-based instruments. The extensive range of risks considered, and the sensitivity analysis of the results, ensures the calibration of the model to a specific reservoir still provides general insights. I find that the total benefits of reservoir operations are generally higher under water pricing. In particular, pricing is a superior instrument for reallocating water between energy and water services under shifting water demand, water scarcity, and level effects in hydroelectricity revenues. However, fixed quotas may be sufficient for multipurpose hydropower regulation where: (i) they provide a central estimate of the shifting demand for and opportunity cost of water services, or (ii) they can be updated to reflect dynamic changes in the value of water and energy services, e.g. through the periodic relicensing governance instrument that was outlined in Chapter 2. In practice, however, the real world is not static and there are many risks for hydropower operators, regulators, and irrigators to manage. Volumetric water pricing should therefore be considered for broader application because it is a flexible method to efficiently allocate water in multipurpose hydropower storage and realise the capacity for hydropower reservoirs to deliver water services.

There are a range of limitations that may provide avenues for further research. The water price only includes a volumetric component and I do not consider the fixed component of water tariffs that are generally used to cover capital expenditure, nor do I model other elements of price design to incorporate intertemporal opportunity costs. Our model assumes that there is no correlation between weather and electricity price levels, and I do not consider stochastic changes in the market value of agricultural produce. Importantly, I have treated environmental flows as fixed when it may be optimal for them to vary with weather and, indeed, to include the economic benefits of environmental flows within calculations of the economic efficiency of water allocation. I have only considered one type of water service (irrigation water supply), when there are many others where water pricing could be used to regulate water reallocation, such as flood control, urban water supply, and environmental flow provision. Finally, the calibration of the model means that there is never any excess irrigation water demand under either pricing or quantity-based regulation. While this specification enables a direct analysis of intertemporal trade-offs between irrigation in period t and hydropower in period $t+1$, it prevents a more thorough consideration of the opportunity costs between hydropower in period t and irrigation in period $t+1$ or irrigation extractions in period t and irrigation extractions in period $t+1$.

Appendix 4.A1. Summary of Variables and Parameters.

Variable/Parameter	***Mathematical Notation***
Quantity of hydropower production (MWh)	e_t
Production parameter of water (MWh/ML)	a
Volume of hydropower extractions (ML)	x_t
Volume of water in reservoir storage at beginning of period t (ML)	S_t
Volume of reservoir inflows (ML)	$\tilde{f}_t$
Volume of irrigation water extractions (ML)	$\tilde{\iota}_t$
Season type (summer, winter)	$\phi = 1, \phi = 2$
Seasonal evaporation rate of storage	$\xi_t = \begin{Bmatrix} \xi_{\varphi_t=1} \text{ if } \phi = 1 \\ \xi_{\varphi_t=2} \text{ if } \phi = 2 \end{Bmatrix}$
Seasonal environmental flows (ML)	$v_t = \begin{Bmatrix} v_{\varphi_t=1} \text{ if } \phi = 1 \\ v_{\varphi_t=2} \text{ if } \phi = 2 \end{Bmatrix}$
Weather type (dry, normal, wet)	d, n, w
Forthcoming weather in the current time period	$\tilde{C}_t$
Weather in the previous time period	B_t
Inflow types, by season and weather (ML)	$F = \begin{Bmatrix} f_{\phi=1,d} & f_{\phi=1,n} & f_{\phi=1,w} \\ f_{\phi=2,d} & f_{\phi=2,n} & f_{\phi=2,w} \end{Bmatrix}$
Random inflow shock (with proportional shifts and associated probabilities)	$\varepsilon_t = \begin{cases} \varepsilon^1 \ w.p\ P^1 \\ \varepsilon^2 \ w.p\ P^2 \\ \quad \ldots \\ \varepsilon^k \ w.p\ P^k \end{cases}$
Marginal revenue from hydroelectricity generation ($/MWh)	r_t
Forward price of electricity generation ($/MWh)	g_t
Carbon market price ($/MWh)	c_t
Coefficient specifying proportion of certificates or offset units accredited per unit of hydroelectricity generation	θ_c
Electricity price level in the next time period ($/MWh)	$\tilde{M}_t$
Electricity price level in the current time period ($/MWh)	L_t
Electricity price level in the previous time period ($/MWh)	K_t
Electricity price level type (low, medium, high)	l, m, h
Electricity price levels ($/MWh)	$L = \{L_l \quad L_m \quad L_h\}$
Rate of carbon market price change	δ_c
Initial carbon market price ($/MWh)	c_0
Fixed seasonal irrigation extractions (ML)	$\bar{\iota}_{\phi_t} = \begin{Bmatrix} \bar{\iota}_{\phi_t=1} \\ \bar{\iota}_{\phi_t=2} \end{Bmatrix}$
Scaling parameter for the water demand/marginal benefit function	$\gamma = \begin{Bmatrix} \gamma_{\phi=1,\ d} & \gamma_{\phi=1,\ n} & \gamma_{\phi=1,\ w} \\ \gamma_{\phi=2,\ d} & \gamma_{\phi=2,\ n} & \gamma_{\phi=2,\ w} \end{Bmatrix}$
Price elasticity of water demand	α
Water price	p_t
Choke volume for irrigation extraction (ML by weather/season)	$\tilde{\iota}_{CHOKE} = \begin{cases} \tilde{\iota}_{CHOKE_{\phi=1,d}} & \tilde{\iota}_{CHOKE_{\phi=1,n}} & \tilde{\iota}_{CHOKE_{\phi=1,w}} \\ \tilde{\iota}_{CHOKE_{\phi=2,d}} & \tilde{\iota}_{CHOKE_{\phi=2,n}} & \tilde{\iota}_{CHOKE_{\phi=2,w}} \end{cases}$
Choke price for irrigation water ($/ML)	p_{CHOKE}
Minimum and maximum storage volume (ML)	S_{MIN}, S_{MAX}
Environmental risk storage volume (ML)	S_{RISK}
Maximum extractions for hydropower	$x_{MAX,\phi_t} = \begin{Bmatrix} x_{MAX,\phi_t=1} \\ x_{MAX,\phi_t=2} \end{Bmatrix}$
Number of time periods	t
Initial reservoir volume	S_0
Discount factor (per seasonal time-step)	ρ

Appendix 4.A2. Calculation of Inflow Volumes for Weather/Season States

To calculate the dry, normal, and summer inflow volumes for summer and winter I first calculate the total rainfall for all months between April 1970 and September 2016. I then obtain the total inflows per season (e.g. April 1970-September 1970; October 1970-March 1970, etc.). For each season type I then identify the 25th and 75th percentile of inflows and categorise seasons below the 25th percentile as dry, between the 25th and 75th percentile as normal, and above the 75th percentile as wet. I then estimate evapotranspiration for each summer/winter by summing the average monthly evapotranspiration in the Arthurs Lake catchment across seasons (i.e. winter = April-September; summer = October-March). Inflows for a particular winter season are estimated as:

$$F = \text{Rainfall} \times 65.629 + (\text{Rainfall} - \text{Evapotranspiration}_{\varphi_{t=2}}) \times 189.271$$

where the surface area of Arthurs Lake is 65.629km^2 and the surface area of the Arthurs Lake Catchment is 251.9km^2 (i.e. catchment area-lake surface area = 189.271 km^2). In the case of all dry summers and a minority of normal summers from 1970-2016, estimated evapotranspiration in the catchment was larger than rainfall. Hence, I assume that summer inflows during dry and normal summers are equal to direct rainfall. The six different types of weather/season states were grouped, and the median calculated of each group to estimate inflows in a dry winter, normal winter, wet winter, dry summer, normal summer, and wet summer.

Appendix 4.A3. Calculation of Random Inflow Shock Parameters

The inflow shock integrates seasonal rainfall variability into the model. In order to estimate a measure of natural variability that could apply to both winter and summer seasons, I calculate the 20th, 40th, 60th and 80th percentile of inflows for each of the six weather/season states and the absolute value of the distance between each percentile and the median value for the corresponding weather/season state. I then calculate the ratio of this distance to the median to estimate, for example, the percentage fall in inflows associated with the 20th percentile and the percentage increase in inflow associated with the 80th percentile. I then average the ratios for the furthest percentiles (20th and 80th) and the closest percentiles (40th and 60th) to the median across all weather/season states, weighting winter values according to the ratio of the volume of dry winter inflows to dry summer inflows, normal winter inflows to normal summer inflows, etc.

Appendix 4.A4. Calculation of Weather/Electricity Price Transitions

I estimate the weather and electricity price transition by calculating the conditional probability of a weather/price type occurring given the weather/price type in the previous time period for the respective time series. Using the electricity price to illustrate:

$$\Pr(B_{t+1} = d | B_t = n) = \frac{frequency\ (B_{t+1} = d, B_t = n\ )}{frequency\ (B_{t+1} = n\ )}$$

The transition matrices for the calibration in Section 4 can be found below.

ϕ_t=1 (summer)		B_t		
		d	n	w
B_{t+1}	d	0.46	0.16	0.2
	n	0.27	0.6	0.6
	w	0.27	0.24	0.2

ϕ_t=2 (winter)		B_t		
		d	n	w
B_{t+1}	d	0.1	0.2	0.46
	n	0.7	0.56	0.27
	w	0.2	0.24	0.27

		L_t		
		l	m	h
L_{t+1}	l	0.5	0.17	0.14
	m	0.5	0.55	0.43
	h	0	0.28	0.43

Appendix 4.A5. Calculation of Irrigation Quotas and Water Demand Functions

To calculate water demand parameters, I first re-align the MWS irrigation delivery periods (summer = 5 months from October to February; winter =7 months from March to September) with the six-month time-step of the model by averaging the monthly winter allowance and adding the share for March to the summer period in the model. I use the adjusted maximum summer volume (19,294 ML) and maximum winter volume (19,447 ML) for the MWS as benchmarks to determine the irrigation extractions under water pricing for dry weather and a medium electricity price level. I then use 1994-2017 rainfall data from the Ross gauge (BOM 2018) to estimate the levels of rainfall in the MWS across the three possible weather states for each season. Average annual rainfall of 487mm is divided roughly evenly between summer (243mm) and winter (245mm). The ratio of dry weather rainfall to normal weather rainfall is used to estimate the shift in the corresponding shift in the water demand function for each season and, hence, the volume of irrigation extractions under water pricing for normal weather and a medium electricity price level. These volumes correspond to the level of fixed irrigation extractions in the summer (15,114 ML) and winter (14,895 ML). The same process is used to calculate irrigation extractions under dry weather and a high electricity price level (summer – 10,195 ML, winter – 10,129 ML). I then use point expansion of the weather demand functions to find the values of parameter γ for different season/weather states. Finally, I substitute the choke price into the marginal benefit function to find the values of the choke price corresponding to the six values of parameter γ. Note that the calculations above and their use in the model involve several assumptions. First, weather states in the MWS and Arthurs Lake are perfectly (positively) correlated. Second, reservoir inflows and water demand are inversely correlated. Third, water demand in the MWS changes in proportion to shifts in rainfall.

Chapter 5

The Cost of Price Stability Controls on Dynamic Water Tariffs

5.1. Introduction

Opportunity costs are fundamental to the management and governance of water resources. Water extracted from storage today detracts from tomorrow's supply. Scarce water allocated to one user limits its availability for others. The foregone benefits of alternative water management decisions are factored into the implicit and explicit cost-benefit analyses that water users conduct every day. Importantly, it is not just private decisions that generate opportunity costs. Different approaches to public regulation of water resources management generate different outcomes. In the design and implementation of water regulation, there is an inherent trade-off between: (i) the revenues or profits of the regulated entity (e.g. a water utility), and (ii) the net public benefits from imposing regulation on that entity. Ultimately, the process of balancing that trade-off, including the resulting distribution of welfare, encompasses social and political considerations beyond water governance. Yet, understanding the economic costs and benefits of alternative regulatory approaches is necessary to assess whether, in practice, the selected approach is the appropriate way to achieve social objectives and, if not, to guide potential reforms.

Water pricing is used to allocate water in many countries (see Dinar et al. 2015; OECD 2010) and there are opportunity costs from deploying alternative water tariff designs.[1] One of the classical conflicts between water pricing objectives is cost recovery versus economic efficiency. Since water systems have large, up-front capital costs, average-cost volumetric pricing will generally lead to inefficiently low levels of water extraction. On the other hand, marginal-cost volumetric pricing may not enable water providers to fully recover their costs (Sibly 2006). The textbook solution is the optimal two-part tariff, including a fixed access charge and a volumetric price (see

[1] In this Chapter I distinguish between a 'water price' and 'water tariff' as follows. A water price is a volumetric charge per unit of water extracted and/or consumed. A water tariff includes the whole package of charges related to water provision, such as a fixed access charge, new connection fee, a volumetric price, and additional charges related to temporal opportunity costs or water scarcity. Hence, a water tariff equates to a volumetric water price if there are no other charges applicable.

Feldman 1972), that is widely used in many urban water systems. However, there are more objectives to consider in tariff design, such as revenue stability, equity and fairness, simplicity, and legality (Griffin 2016). Resolving conflicts across multiple water policy objectives is no simple matter. In fact, failing to account for the potential outcomes from prioritising one objective, or implementing a particular tariff design, can create sub-optimal and, sometimes, perverse outcomes. For example, the Increasing Block Tariff (IBT) structures commonly used to promote equity in urban water provision can actually be regressive: low or no volumetric price on initial volumes of consumption can lead to higher access charges, with multiple poor households that share a single connection subsidising rich households who have their own (Dahan & Nisan 2007; Whittington 1992; Wichelns 2013; Young & Whittington 2016).

In theory, the social benefits derived from water resources could be raised by incorporating the marginal opportunity cost of withdrawals into the volumetric component of water tariffs (see Griffin 2016 for a detailed discussion). These opportunity costs may include: (i) the marginal value of natural water, or the in-situ value of an additional unit of water in a river or lake; and (ii) marginal capacity cost, or the additional volumetric charge required to balance total supply and total demand when water is scarce, and thereby efficiently schedule water supply expansion (see Grafton et al. 2014; Turvey 1976). In the context of water storage which is depletable in the short- and/or long-term, such as an aquifer or reservoir, a third type needs to be considered: marginal user cost. This is the foregone benefit of having an additional unit of water available in the future. If the time-discounted marginal benefit of an additional unit of future water extraction or storage is higher than the marginal benefit of a present-day extraction, then there is an opportunity cost associated with not leaving that water in storage. The intuition is straightforward: groundwater extractions today increase tomorrow's marginal pumping costs; low surface water supplies in the future may require urban water systems to bring costly desalination plants online; or, the value of irrigation extractions may be higher in a future dry and/or hot season when rainfall is lower and/or evapotranspiration is higher.

The marginal user cost of water extractions can be estimated and valued (see Moncur & Pollock 1988). In practice, however, opportunity costs are rarely incorporated into water tariffs and the potential benefits of dynamically efficient, scarcity-based water pricing are not realised. Under droughts or other supply constraints, water regulators and utilities generally pursue non-price approaches, such as rationing or supply-side investments, to manage excess demand for water (Olmstead & Stavins 2009). There is a large literature on the resulting welfare losses and, more generally, the potential gains from efficient water pricing (e.g. Garcia & Reynaud 2004; Grafton & Kompas 2007; Grafton & Ward 2008; Lopez-Nicolas et al. 2018; Molinos-Senante & Donoso 2016; Nauges & Whittington 2017; Renzetti 1992; Roibas et al. 2018; Sağlam 2015; Timmins 2002).

Why, then, is marginal user cost not commonly incorporated into water tariff design? Two potential reasons standout. First, it is difficult to calculate marginal user cost precisely. Foregone future benefits need to be estimated on the basis of the future state of dynamic natural, social, and economic systems. If scientific and economic modelling is used to form those estimations, and the resulting water prices, then the process may be too complex for water users to understand and accept. In that case, an important set of objectives for water tariff design, namely simplicity and transparency, may be violated. Second, and perhaps most importantly, a key consequence of incorporating marginal user cost into tariffs is that water price spikes will occur in the presence or expectation of water scarcity, excess water demand, or other circumstances where the future benefits of maintaining water in storage become very high. Rapid increases in the price of an essential service are politically undesirable for governments that own water providers and/or oversee their regulation. The persistent challenge of cost recovery in water services provision (see Easter and Liu 2005) demonstrates that social norms regarding fairness and equity, or perceptions thereof, have historically been prioritised over economic efficiency in the formulation and regulation of water tariffs. A range of other social, political, and economic justifications may be proposed for controlling price variability and underpricing water, such as promoting investment in an emerging industry or protecting the welfare of a powerful interest group. Whatever the reasons for not incorporating marginal user cost into water tariffs, the foregone benefits should be estimated to enable decisions on whether they are actually outweighed by the perceived benefits of economically inefficient water pricing.

This Chapter estimates the costs of prioritising price stability over economic efficiency in water tariff design. I use hydro-economic modelling to compare outcomes from: (i) a price stability tariff wherein the volumetric price is averaged over several periods and there is a fixed water scarcity premium; and (ii) a dynamic tariff structure that estimates the marginal user cost of water extraction and includes a water scarcity premium that is contingent on expected storage levels. I consider these alternative regulatory approaches for an emerging application of water pricing: the provision of irrigation water from multipurpose hydropower reservoirs. In this context, the hydropower operator is also a water services provider that sells water to irrigators according to a tariff overseen by a regulatory agency. The opportunity cost of irrigation withdrawals is foregone hydroelectricity generation. In order to model the price stability and marginal user cost tariffs, I draw on current and previous iterations of the tariff structure used in one of the first real-world applications of water pricing to the governance of multipurpose hydropower reservoirs (see Hydro Tasmania 2015, 2017). I simulate the application of these tariff structures to water allocation using stochastic dynamic programming and estimate the relative costs of deploying price stability controls across: (i) foregone hydropower profits, (ii) foregone hydroelectricity generation, (iii) additional electricity purchases by the hydropower company, and (iv) the reduced efficiency of water allocation (i.e. the total net benefits of water use). A key component of the model is an electricity supply obligation that requires the hydropower operator to purchase electricity, and thereby incur additional costs, if there is insufficient water storage to fulfil that obligation.

Although I consider a specific application of water pricing to multipurpose hydropower reservoirs, the insights are relevant to other applications where the variable costs of water provision can fluctuate significantly, such as: energy-intensive irrigation systems; urban water systems that include an expensive backstop technology, such as desalination or wastewater treatment plants; and water systems where additional supply can be purchased in water markets at variable prices. The remainder of this section provides a review of related literature and describes the Chapter's contribution. Section 5.2 outlines the hydro-economic model of reservoir operations and irrigation extractions, with a focus on alterations to the model already outlined in Chapter 4 of this thesis. Section 5.3 provides details on how the model is recalibrated to Arthurs Lake, Tasmania. Section 5.4 presents the results, including a detailed sensitivity analysis of key parameters associated with electricity markets, water demand, and operating constraints. Section 5.5 discusses the policy implications of the results. Section 5.6 concludes with an overview of the study's limitations and directions for further research.

4.1.1. Literature Review and Contribution

Many previous studies have considered the theory of water tariff design and the application of water pricing to urban, agricultural, and industrial water systems. (see reviews by Dinar et al. 2015; Griffin 2015; Johansson et al. 2002; Tsur & Dinar 1997). Building on foundational research on the marginal cost of water supply (Hanke & Davis 1973; Turvey 1976), two-part tariffs (Feldman 1972), and the scarcity value of water (Moncur & Pollock 1988), various studies have shown that dynamic water pricing allocates water more efficiently than non-price approaches, such as water rationing, and water tariffs that do not account for intertemporal opportunity costs (Grafton & Kompas 2007; Grafton & Ward 2008; Olmstead & Stavins 2009). The welfare costs of sub-optimal approaches to water pricing have been assessed in detail for specific urban contexts (e.g. Mansur & Olmstead 2012; Renzetti 1992). The trade-offs between competing objectives in water tariff design, such as cost recovery and equity, have been considered (Ruijs 2009; Schoengold & Zilberman 2014), and a variety of tariff structures have been proposed to address specific topics, such as providing incentives for sustainable water use (Elnaboulsi 2009), jointly addressing equity and scarcity considerations (Molinos-Senante & Donoso 2016), and enabling water systems to supply peak water demand (Feldman 1975; Hanemann 1997).

In the context of reservoirs and water storage management, Pulido-Velazquez et al. (2013) presented a process to determine the basin-wide 'marginal resource opportunity cost' of water extractions. The authors conduct hydro-economic simulations to estimate the MROC, or user cost, of water extractions for a given set of system states. The raw values are then processed into a storage-dependent step function for particular reservoirs. Macian-Sorribes et al. (2015) use the aforementioned approach to assess the benefits of a scarcity-based pricing regime for a multi-reservoir irrigation system, creating a schedule for marginal user cost that is a function of the cumulative reservoir storage across the basin. Lopez-Nicolas et al. (2018) also use the step-based MROC approach to model a dynamic, increasing block tariff for urban water pricing where the second (highest) block increases across four levels as basin-wide storage falls below corresponding thresholds.

Khadem et al. (2018) estimate the economic value of interannual storage for a large multi-storage and multi-purpose water system. Incorporating these values into optimal reservoir operations reduces the severity and costs of water scarcity. Chu and Grafton (2018) explain and derive 'risk-adjusted user cost' (RAUC) in the context of dynamic, scarcity-based urban water pricing that enables optimal timing of supply-side investments and avoids welfare-reducing water restrictions. The RAUC premium accounts for the magnitude and frequency of rainfall variability, the risk aversion of water consumers to water restrictions, the ratio of return flows to transmission system leakage, and the intertemporal discount rate. The authors calculate the RAUC for Canberra, Australia and discuss the policy implications, including that large water users should be charged a higher RAUC. Grafton et al. (2014) use stochastic dynamic programming to define dynamically efficient water prices for an urban water system subject to inflow uncertainty. It is shown that the management of water demand through dynamic, scarcity-based pricing could have prevented large welfare losses from premature investment in costly, supply-side infrastructure.

The current Chapter makes two contributions. First, it is the only study to date that considers water tariff design in the context of regulating multipurpose hydropower reservoirs. This is an important emerging topic as new and existing hydropower reservoirs are called on to provide more water services in response to climate change and burgeoning water demand (see the detailed discussion of this issue in Chapter 2 of this thesis). Although water pricing has significant potential to provide hydropower companies with the flexibility and incentives to deliver these services to irrigators, cities, and other water users, its effectiveness is contingent on tariff design and, in particular, whether and how opportunity costs are incorporated. For multipurpose hydropower reservoirs, marginal user cost is an important consideration. From the perspective of hydropower companies, key features of the global energy transition include: (i) the increased value of hydropower providing firming capacity as the proportion of variable electricity generation from solar and wind increases, and (ii) wholesale price volatility as markets restructure and climate and energy policies change (Anghileri et al. 2018; Gaudard et al. 2016). In competitive wholesale electricity markets, both these factors may cause rapid increases in the marginal revenue from hydroelectricity generation. Further, variability in reservoir inflows and the demand for water services means that multipurpose operations could, in the presence of water scarcity, constrain hydropower companies' electricity production and revenues. Under dynamic water tariffs that incorporate marginal user cost, both electricity price spikes and water scarcity would lead to water price spikes. While water price variability may generate some negative externalities or be inconsistent with social norms, other areas of water governance demonstrate that price controls and inefficient tariffs generate social welfare losses and impose costs on water providers. This Chapter provides regulators and hydropower operators with insights into these trade-offs in order to support the increased provision of water services by multipurpose hydropower reservoirs.

The second contribution of the Chapter is the demonstration of a heuristic to estimate marginal user cost under stochastic conditions that does not require hydro-economic modelling and could be explained to all water users. This heuristic can be adapted to allocating water in a range of water systems where rapid increases can occur in the variable costs of water provision and/or excess water demand imposes additional costs on the water service provider. Although previous studies have used mathematical programming and other techniques to estimate marginal user cost and show how it could be incorporate it into real-world water tariffs (Chu & Grafton 2018; Macian-Sorribes et al. 2015), these approaches may not be possible in all contexts because the requisite data or software is not available, the institutional capacity does not exist to use them, or they are not accepted by water users and other stakeholders because the calculation process is not readily understandable by a layperson.

5.2. Model of Multipurpose Hydropower Operations and Water Tariffs

I modify the stochastic dynamic programming model of reservoir operations developed in Section 4.2 of Chapter 4. The model considers the optimisation problem of a profit-motivated hydropower company managing a multipurpose reservoir. The reservoir supplies water to electricity generation, irrigation, and environmental flows; water withdrawals are rivalrous between these uses. The marginal benefit of allocating water to electricity production, irrigated agriculture, or storage varies according to stochastic changes in reservoir inflows, electricity market prices, and irrigation water demand.

The modifications to the hydro-economic model outlined in Chapter 4 are summarised as follows. The hydropower company is obliged to sell a minimum level of electricity each period; if a shortfall occurs, then the company must make up the deficit by purchasing electricity in the local market or importing it from a neighboring market. In either case, these purchases are subject to a premium that is a fixed proportion of the prevailing price the company receives for generating hydroelectricity in the same period. Reservoir operations are regulated so that water cannot be extracted for hydropower below a specified level of storage, thereby guaranteeing a minimum level of irrigation extractions. Further, irrigators cannot extract water below a specified storage to protect aquatic ecosystems and the recreational fisheries they support in the reservoir. The analysis focuses on two alternative approaches to irrigation water pricing: (i) a price stability tariff wherein the water price incorporates the average electricity price across previous periods and there is a constant water scarcity premium; and (ii) a marginal user cost tariff that incorporates the expected marginal hydroelectricity revenue in the forthcoming period, plus a dynamic water scarcity premium that is applied when reservoir levels in the forthcoming period are expected to be low (and the hydropower company expects to purchase electricity at a premium). In addition, I consider the water tariff from Chapter 4 wherein the volumetric water price is the marginal value of hydropower generation in the same period.

Below I redefine certain key variables and explain modifications to the model. Section 4.2 of Chapter 4 provides an in-depth exposition of the original model and Table 5.1 in Section 5.3 of the current Chapter provides a summary of the model parameters for this application.

5.2.1. Electricity Supply Obligation and Spot Market Purchases

Recall that the quantity of hydroelectricity produced during period t is:

$$e_t = \frac{1}{a} \times x_t$$

where x_t is the volume of water releases from the reservoir to the hydropower plant that are scheduled at the beginning of period t, and a is the fixed production parameter of water that specifies the volume of water required to produce a unit of electricity.

The hydropower operator is required to supply a minimum level of electricity each period, e_{MIN}, in order to satisfy a quantity-based contractual or licensing arrangement, such as a purchase power agreement or energy security obligations. The maximum amount of electricity supply per period, e_{MAX}, equates to the electricity generated by the maximum level of hydropower extractions per period, x_{MAX}. If hydroelectricity generation is less than e_{MIN}, the hydropower company must purchase the shortfall in a forward market. There is a penalty associated with this purchase that reflects either: (i) the cost of importing electricity through a transmission connection from a neighboring market; (ii) the additional cost of exercising a hedging instrument or entering a contract market to meet supply obligations; (iii) the higher cost of alternative generation technologies, or (iv) the opportunity cost of constraints on the hydropower company's market activity, e.g. being unable to sell high-value, low-probability options contracts or having reduced flexibility to bid into the wholesale spot market.

The marginal cost of the hydropower company's electricity purchase is ψg_t, where $g_t(L_t)$ is the price of the forward contract that the hydropower company sells for the generation it schedules at the beginning of each period; L_t is the electricity price level in period t; and ψ is a constant, deterministic parameter. I specify that $\psi > 1$ so that the electricity company's forward contract purchase is more expensive than the electricity it sells and, hence, there is a penalty for not meeting e_{MIN}. The total cost of purchasing electricity in period t is the marginal cost, $\psi g_t(L_t)$, multiplied by the volume of electricity purchases, $\max(0, e_{MIN} - e_t(x_t))$. Note that the hydropower company may have no choice to purchase electricity, and incur the associated penalty, due to insufficient water being held in reservoir storage, or optimally choose to do so because electricity prices are expected to be higher in the following period.

5.2.2. Excess Demand for Irrigation Water and Storage Constraints

The specification of irrigation water demand is modified to allow excess water demand. Here, the irrigation company cannot extract water if residual storage (after hydropower extractions, inflows, evaporation losses, and environmental flow extractions) is less than S_{RISK}, the minimum level of storage required to manage environment quality in the reservoir's ecosystems and support recreational fishing. Hence, irrigation extractions in period t are

$$\tilde{\iota_t} = \begin{cases} \gamma_t(p_t)^{\alpha} \ if \ \ \gamma_t(p_t)^{\alpha} \leq S_t + \tilde{f_t} - x_t - \xi_t S_t - v_t - S_{RISK} \\ \max(0, S_t + \tilde{f_t} - x_t - \xi_t S_t - v_t - S_{RISK}) \ otherwise \end{cases}$$

I carryover the specification in Chapter 4 of a fixed value for S_{RISK} across both summer and winter seasons. Note that the environmental risk condition means that irrigation extractions are now a function of the weather state in the previous period, B_t, the water price, p_t, and hydropower extractions, i.e. $\tilde{\iota}_t = \tilde{\iota}_t(B_t, L_t, x_t)$. Since irrigation extractions occur after all other extractions in a given period (see Figure 4.6 in Chapter 4), the volume of hydropower extractions and inflows affect whether enough storage is available to meet irrigators' total water demand. However, a storage buffer manages the possibility of excess irrigation water demand occurring. The hydropower company is prevented from extracting water below a constant minimum level, S_{IRR}. I define the storage constraints such that $S_{MIN} < S_{RISK} < S_{IRR}$, where S_{MIN} is the physical minimum level of functional reservoir storage. The size of the gap between S_{IRR} and S_{RISK} each season determines the guaranteed minimum level of water available for irrigation extractions after inflows, evaporation, and environmental flows occur. This minimum level may be set to ensure that excess irrigation water demand does not occur, or that it is limited.

5.2.3. Water Tariffs

I consider three water tariff structures: (i) Standard Volumetric Tariff (SV Tariff), (ii) Price Stability Tariff (PS Tariff), and (iii) Marginal User Cost Tariff (MUC Tariff). An irrigation company earning zero profits pays the hydropower company to withdraw water from the reservoir on behalf of its customers. As in Chapter 4, I do not include the fixed costs of dam construction or water conveyance in the water tariff. Further, I assume full cost-pass through by the irrigation company to farmers in the same period. This means that the water tariff in all three cases consists of a volumetric water price.

5.2.3.1. Standard Volumetric Tariff

This reference case is the volumetric approach defined previously in Chapter 4. The hydropower operator charges the irrigation company a water price that reflects the value of foregone generation in the same period:

$$p_t = \frac{1}{a} \times (g_t(L_t) + \theta^c \bar{c})$$

where L_t is the forward electricity price level in the current period and $L_t = \{L_l \quad L_m \quad L_h\}$ is one of three possible forward electricity price levels (low, medium, high); $\bar{c}$ is the constant price per unit of hydroelectricity in renewable energy certificate (REC) or carbon offset (CO) markets (henceforth ‘carbon markets’); and $\theta^c \in (0, 1)$ is a constant parameter specifying the number of certificates or offset units accredited per unit of hydroelectricity generation.

5.2.3.2. Price Stability Tariff

This approach adapts the SV Tariff in two ways. First, a fixed scarcity premium is included to reflect that electricity will need to be purchased by the hydropower company in some years when storage levels are low. The premium consists of: (i) a parameter, ω, that represents the long-term probability of electricity purchases being required in a given period; and (ii) the additional cost of those purchases relative to selling hydroelectricity, $(\psi - 1) \times g_t(L_t)$.

Second, fluctuations in the water tariff that farmers face as electricity revenues change are smoothed by averaging the water tariff across n periods, including the current period and the previous $n-1$ periods. This requires a state variable to be defined for the electricity price level for each of the $n-1$ previous periods. Recall that Chapter 4 defined the following variables affecting the hydropower company's generation scheduling decision at the beginning of period t: the current period electricity price level, L_t, and the previous period electricity price level, K_t. Hence, there are an additional $n-2$ state variables mapping the history of electricity price level movements. For the purposes of a simple illustration, I use the $n = 3$ case that is modelled in Section 5.5 of this Chapter to outline the water tariff structure in this case:

$$p_t = \frac{1}{a} \times \left(\frac{(1 + \omega(\psi - 1))g_t(L_t) + (1 + \omega(\psi - 1))g_t(K_t) + (1 + \omega(\psi - 1))g_t(J_t)}{3} + \theta^c \bar{c} \right)$$

where J_t is the electricity price level two periods ago at the beginning of period t. Note that this tariff structure captures the main elements of the one used in practice (from 2017 onwards) by the hydropower company operating the multipurpose reservoir which the model is calibrated to in Section 5.3 (see Hydro Tasmania 2017c, 2018).

5.2.3.3. Marginal User Cost Tariff

The marginal user cost of irrigation water extractions in period t is the time-discounted, expected value of a one unit increase in reservoir storage in period $t + 1$, or

$$\mathrm{MUC}_t = \frac{1}{1+\rho} E\left(\frac{\partial V_{t+1}(S_{t+1}, \phi_{t+1}, B_{t+1}, K_{t+1}, L_{t+1})}{\partial S_{t+1}}\right)$$

where S_{t+1} is the volume of reservoir storage at the beginning of period $t + 1$ and V_{t+1} is the value of a particular combination of states across storage volumes, season (ϕ_{t+1}), past weather (B_{t+1}), past electricity price level (K_{t+1}), and current electricity price level (L_{t+1}) at the beginning of period $t + 1$.

The marginal user cost represents the expected opportunity cost to the hydropower generator of a unit of period t irrigation extractions reducing storage volume by one unit at the start of period $t + 1$. Relative to the SV Tariff, a tariff incorporating the marginal user cost will be higher when: (i) storage is expected to be low at the start of period $t + 1$ such that the hydropower operator cannot meet the minimum level of electricity supply through its own generation (i.e. $\frac{1}{a} \times (E(S_{t+1}) - S_{IRR}) < e_{MIN}$), and/or (ii) when marginal hydroelectricity revenue is expected to be higher in $t + 1$, i.e. $E(r_{t+1}(L_{t+1})) > r_t(L_t)$.

Exact values for MUC_t can be calculated through the stochastic dynamic programming (SDP) framework used to solve the original version of the model in Chapter 4. Here, we develop an alternative ‘rule-of-thumb’ approach that is less exact but easier to apply in practice. In the context of incorporating basin-wide opportunity costs into dynamic irrigation water pricing, Macian-Sorribes et al. (2015) note that internally generated values for opportunity costs are dependent on the solution algorithm. The determination of a tariff by such algorithms could be perceived as a ‘black-box’ calculation by the irrigators paying it. As Griffin (2016) notes, simplicity and transparency are important objectives for water tariff design. Further, hydropower operators or regulatory agencies do not necessarily have the resources or data to use SDP algorithms to set water tariffs. Hence, I use the following heuristic to estimate the MUC tariff in period t:

1. Assume that any extra unit of storage at the beginning of period $t+1$ would be used to generate hydroelectricity.

2. Estimate expected marginal hydropower revenue in period $t+1$. Divide this value by the production parameter of water. The result is the main component of the volumetric water price.

3. Calculate the expected volume of storage at the beginning of period $t+1$ by: (i) assuming that period t hydropower extractions are equal to the volume required to meet the electricity supply obligation, (ii) estimating the expected volume of inflows, and (iii) estimating the expected volume of irrigation extractions if the water price is equal to the one calculated in Step 2 above.

4. If the expected volume of storage at the beginning of period $t+1$ is less than the water volume equating to the minimum electricity supply, then the volumetric water price is augmented by a premium that reflects the higher marginal cost of the hydropower operator purchasing electricity in period $t+1$.

Formally, the water tariff is defined as:

$$p_t = \begin{cases} \frac{1}{a} \times \left(E(g_{t+1}(L_t)) + \theta^c \bar{c}\right) \ if \ \frac{1}{a} \times \left(E(S_{t+1}|x_t = x(e_{MIN})) - S_{IRR}\right) \geq e_{MIN} \\ \frac{1}{a} \times \left((\psi - 1) \times E(g_{t+1}(L_t)) + \theta^c \bar{c}\right) \ if \ \frac{1}{a} \times \left(E(S_{t+1}|x_t = x(e_{MIN})) - S_{IRR}\right) < e_{MIN} \end{cases}$$

$$E(S_{t+1}|x_t = x(e_{MIN})) = S_t + E(\widetilde{f_t}(B_t, \phi_t)) - E(\widetilde{\iota_t}(B_t, L_t)) - \xi_t S_t - v_t$$

Recall that ξ_t is the fixed evaporation rate of water held in storage at the beginning of period t; v_t is the seasonal volume of environmental flow deliveries; ϕ_t is the season; and $\widetilde{f_t}$ is the volume of reservoir inflows, which are unknown at the beginning of period t and are a function of the previous period's weather type, B_t. The term $(\psi - 1)$ incorporates a water scarcity premium on foregone marginal electricity revenues, $g_{t+1}(L_t)$, when the hydropower operator is expected to purchase electricity in the next period. The expected volume of irrigation extractions, $\tilde{\iota_t}$, is calculated using the period t water price that would prevail without the water scarcity premium.

The term $E(S_{t+1}|x_t = x(e_{MIN}))$ is the hydropower operator's expectation (at the beginning of period t) of the storage volume at the beginning of period $t + 1$ if hydropower extractions during period t are equivalent to the minimum electricity supply obligation. This condition isolates the impact of irrigation extractions from the joint impact of period t hydropower and irrigation extractions on whether or not the hydropower operator is expected to purchase electricity in period $t + 1$. The rationale for this assumption is two-fold. First, it counterbalances the water scarcity premium being triggered in period t regardless of how much of the minimum electricity requirement is expected to be supplied through period $t + 1$ electricity purchases. Second, it prevents moral hazard by removing the incentive for the hydropower company to operate the reservoir at maximum capacity in every period to trigger the water scarcity premium and make windfall profits if electricity purchases are not actually required in the next period.

Note that I drop the time discount from the expected future value of storage because, consistent with Chapter 4, period t irrigation charges are received as revenues by the hydropower company in period $t + 1$. Hence, incorporating the discount rate in the water tariff as well would result in the revenue from provision of irrigation water being discounted twice, and thereby decrease the incentives for the hydropower company to leave water in the reservoir and potentially bias the results.

5.2.4. Summary of Profit Functions and Optimisation Problems

I solve the hydropower operators' optimisation problem under the different water tariffs. The irrigator's water extractions (and profits) in a given period are a function of the water price, the weather/season state, and the residual storage after water has been extracted for hydropower, released to environmental flows, and evaporation has occurred. The hydropower operator only directly controls the amount of water allocated to hydropower generation. The revenues that the hydropower operator receives from the previous period's irrigation extractions varies according to shifts in water demand.

Below I provide a summary of the profit functions and optimisation problems for the three water tariffs outlined in Section 5.2.3. The reader is referred to Chapter 4 for a full exposition of the optimisation procedure and the transition of state variables. I define a finite planning horizon, $t = (1,2,\ldots.T)$, initial values of the state variables, and the transition probabilities for the previous period's weather state (B_t) and current period electricity price level (L_t). The final period hydropower profit remains the sum of the value of the accessible water in storage and irrigation revenues from the penultimate period. There is no electricity supply obligation in the final period. I continue to assume that there are no fixed costs associated with electricity generation and irrigation water supply, nor variable costs associated with electricity generation.

Standard Volumetric Tariff

For the SV Tariff, hydropower profits are comprised of the current period's electricity revenues, minus the cost of any electricity purchases, plus irrigation revenues from the previous period:

$$\pi_t^H(B_t, K_t, L_t, x_t) = \frac{1}{a} \times x_t \times r_t(L_t) - \psi g_t(L_t) \times \max(0, e_{MIN} - e_t(x_t)) \\ + i_{t-1}(B_t, K_t) \times p_{t-1}(K_t)$$

where K_t is the electricity price level in period $t-1$ and x_t is the volume of hydropower extractions that the operator schedules at the beginning of period t.

The irrigation net profit function, π_t^I, for water pricing is:

$$\pi_t^I(B_t, L_t, x_t) = \frac{\alpha}{\gamma_t(B_t)^{\frac{1}{\alpha}}(\alpha+1)} \left(\tilde{\imath}_t^{\frac{\alpha+1}{\alpha}}(B_t, L_t, x_t) - i_{CHOKE_t}^{\frac{\alpha+1}{\alpha}}(B_t) \right) \\ + p_{CHOKE} \times i_{CHOKE_t}(B_t) - p_t(L_t) \times \tilde{\imath}_t(B_t, L_t, x_t)$$

The hydropower operator controls the volume of water released to the power station in each period to maximise the net present value of profits over time. The irrigator maximises the within-period benefits of its water extractions subject to the water price.

The formal problem is:

$$\max_{x_t} E_1 \sum_{t=1}^{T} \frac{\pi_t^H(B_t, K_t, L_t, x_t)}{(1+\rho)^t}$$

subject to: operation and regulatory constraints defined in Chapter 4 and modifications specified in Section 5.2.2; the initial conditions for the season (ϕ_t), current period's electricity price level (L_1), previous period's weather (B_1) and price level (K_1), and the terminal profit condition; and the transition of the state variables (t, B_t, K_t, L_t).

The profit-maximising hydropower generation schedule from t=1 to t=T is found with stochastic dynamic programming (SDP). The Bellman equation is

$$V(S_t, \phi_t, B_t, K_t, L_t) = \max_{x_t} \left[\pi_t^H(S_t, \phi_t, B_t, K_t, L_t) + \frac{1}{1+\rho} EV(S_{t+1}, \phi_{t+1}, B_{t+1}, K_{t+1}, L_{t+1})\right]$$

Price Stability Tariff

The hydropower profit function, optimisation problem, and associated Bellman equation are augmented by the additional electricity price state variables corresponding to the number of previous periods over which the average water price is calculated. For the $n = 3$ case, this means that I need to include both J_t and I_t, the electricity price level from three periods ago, because of the lag in the hydropower operator's receipt of irrigation revenues. The Bellman equation is:

$$V(S_t, \phi_t, B_t, I_t, J_t, K_t, L_t,) = \max_{x_t} \left[\pi_t^H(S_t, \phi_t, B_t, I_t, J_t, K_t, L_t) + \frac{1}{1+\rho} EV(S_{t+1}, \phi_{t+1}, B_{t+1}, I_{t+1}, J_{t+1}, K_{t+1}, L_{t+1})\right]$$

Marginal User Cost Tariff

An additional state variable for the weather two periods ago, A_t, is added to the model. This is necessary because the period t irrigation revenues received by the hydropower company are determined by the period $t-1$ irrigation extractions that, in turn, are a function of the period $t-1$ water tariff and expectations regarding the period t storage volume and period $t-1$ inflows that were formed on the basis of the known weather state in period $t-2$. The hydropower operator's profit function is:

$$\pi_t^H(A_t, B_t, K_t, L_t, x_t) = \frac{1}{\alpha} \times x_t \times r_t(L_t) - \psi g_t(L_t) \times \max(0, e_{MIN} - e_t(x_t)) + i_{t-1}(A_t, B_t, K_t) \times p_{t-1}(K_t)$$

The irrigator's profit function is:

$$\pi_t^I(B_t, L_t, x_t, S_t) = \frac{\alpha}{\gamma_t(B_t)^{\frac{1}{\alpha}}(\alpha+1)}\left(\tilde{\imath}_t^{\frac{\alpha+1}{\alpha}}\,\tilde{\imath}_t(B_t, L_t, x_t, S_t) - i_{CHOKE_t}{}^{\frac{\alpha+1}{\alpha}}(B_t)\right) + p_{CHOKE} \times i_{CHOKE_t}(B_t) - \; p_t(L_t) \times \tilde{\imath}_t(B_t, L_t, x_t, S_t)$$

Finally, the Bellman Equation is:

$$V(S_t, \phi_t, A_t, B_t, K_t, L_t) = \max_{x_t}\left[\pi_t^H(S_t, \phi_t, A_t, B_t, K_t, L_t) + \frac{1}{1+\rho} EV(S_{t+1}, \phi_{t+1}, A_{t+1}\, B_{t+1}, K_{t+1}, L_{t+1})\right]$$

4.3. Recalibration of Model to Arthurs Lake, Tasmania

The model of hydropower operations and irrigation extractions is reapplied to the multipurpose Arthurs Lake reservoir and Midlands Irrigation Scheme considered in Chapter 4. The parameters and their derivation are the same as Chapter 4 unless specified below. Table 4.A1 in Chapter 4 provides a full summary of all variables and parameters, and their respective mathematical notation; Table 5.1 below summarises the parameter values used in this Chapter. All monetary values are reported in 2018 Australian dollars (AUD). Note that the hydro-economic modelling of Arthurs Lake operations is a calibration exercise and not a case study for the purpose of proposing regulation or management reforms for that particular reservoir. Instead, our purpose is to develop general insights into the costs of price stability controls, relative to the MUC Tariff, and how they change with different parameter specifications.

The reservoir storage level that irrigation water extractions cannot be extracted below, S_{RISK}, remains at the medium environmental risk level defined in operation rules for Arthurs Lake (164,000 ML). The level constraining hydropower extractions, S_{IRR}, is set at the June 1st minimum value (217,000 ML) under the water supply agreement between Hydro Tasmania and Tasmania Irrigation for the Midlands Irrigation Scheme. I increase the minimum storage volume, S_{MIN}, to 150,000 ML to reduce the size of the state space that needs to be considered in the application of the solution algorithm. The ratio between the electricity price level and the cost of the hydropower operator purchasing electricity, ψ, is 1.27. This value equates to the average percentage difference between the monthly peak and average spot price for the Victorian NEM market from 1999-2016. Prior to the establishment of regulated Tasmanian electricity prices in 2017, Hydro Tasmania used this peak-average difference to calculate the cost of increased net imports from neighboring Victoria within the scarcity premium component of the irrigation water tariff. Note that this scarcity premium was allowed under the terms of the Hydro Tasmania water license which specifies that newly established irrigation schemes can be charged a water price equating to the value of foregone hydropower generation.

In order to simulate the impact of large fluctuations in electricity and water prices, I adopt the high electricity price level for the ‘price spike’ risk analysis in Section 4.2.2. of Chapter 4: \$102.31. The minimum volume of electricity generation per season, e_{MIN}, is set at an arbitrary level of 30%

of maximum generation, or 37375 MWh. In the context of Arthurs Lake, hydropower extractions equating to less than this volume (<19,700 ML) occurred 5 times across the 40 summer/winter seasons between 1995 and 2015, and average extractions were 46,115 ML per season. Section 5.4.2 provides a sensitivity analysis of this key parameter.

The PS Tariff is consistent with the water price calculation method used by Hydro Tasmania from 2017 onwards, although not for the Midlands Irrigation Scheme because of the scheme's mini-hydropower plant that provides a natural hedge against water price fluctuations. The rationale provided for this averaging approach has been smoothing out the impact of electricity price spikes on water prices, and thereby assisting the planning activities of irrigators and other stakeholders (Hydro Tasmania 2017b, 2017c, 2018). Notably, the Tasmanian government has a stated goal of increasing the value of the state's agricultural production ten-fold to 2050, with a particular focus on financing and constructing new irrigation infrastructure through the 'Pipeline to Prosperity' scheme (see Infrastructure Tasmania 2018). In 2017, when price stability controls were first introduced, the volumetric water price was averaged over 5 years; this was subsequently extended to 10 years in 2018. Here, I only average the PS Tariff across 3 seasons (or 1.5 years) instead of 20 seasons (or 10 years) because matching the full 10-year time span would require a further 17 state variables to be added to the model. The parameter in the PS Tariff for the fixed probability of the hydropower operator purchasing electricity due to insufficient reservoir storage, ω, is the value used to calculate the water scarcity premium in Hydro Tasmania (2017).

Variable	Mathematical Notation	Value
Minimum and maximum storage volume	S_{MIN}, S_{MAX}	150000 ML, 449000 ML
Risk storage level volume	S_{RISK}	164000 ML
Irrigation buffer storage volume	S_{IRR}	217000 ML
Inflows, by season and weather type	$F = \begin{Bmatrix} f_{\phi=1,d} & f_{\phi=1,n} & f_{\phi=1,w} \\ f_{\phi=2,d} & f_{\phi=2,n} & f_{\phi=2,w} \end{Bmatrix}$	$\begin{Bmatrix} 18227 \text{ ML} & 22679 \text{ ML} & 39375 \text{ ML} \\ 59850 \text{ ML} & 88207 \text{ ML} & 122905 \text{ ML} \end{Bmatrix}$
Random inflow shock	ε_t	$\varepsilon_t = \begin{cases} 0.87 \text{ w.p } 0.2 \\ 0.97 \text{ w.p } 0.2 \\ 1 \text{ w.p } 0.2 \\ 1.03 \text{ w.p } 0.2 \\ 1.13 \text{ w.p } 0.2 \end{cases}$
Evaporation rate of storage	$\xi_t = \begin{Bmatrix} \xi_{\phi_t=1} \\ \xi_{\phi_t=2} \end{Bmatrix}$	$\begin{Bmatrix} 0.138 \\ 0.049 \end{Bmatrix}$
Seasonal environmental flows	$v_t = \begin{Bmatrix} v_{\phi_t=1} \text{ if } \phi = 1 \\ v_{\phi_t=2} \text{ if } \phi = 2 \end{Bmatrix}$	$\begin{Bmatrix} 4000 \text{ ML} \\ 1000 \text{ ML} \end{Bmatrix}$
Electricity price levels ($/MWh)	$L = \{L_l \quad L_m \quad L_h\}$	$\{\$31.96 \quad \$44.40 \quad \$102.31\}$
Conversion factor for water releases into energy (MWh/ML)	a	0.5272
Maximum extractions for hydropower	$x_{MAX,\phi_t} = \begin{Bmatrix} x_{MAX,\phi_t=1} \\ x_{MAX,\phi_t=2} \end{Bmatrix}$	$\begin{Bmatrix} 65681 \text{ ML} \\ 66044 \text{ ML} \end{Bmatrix}$
Price elasticity of water demand	α	-0.81
Fixed seasonal irrigation extractions (ML)	$\bar{\iota}_{\phi_t} = \begin{Bmatrix} \bar{\iota}_{\phi_t=1} \\ \bar{\iota}_{\phi_t=2} \end{Bmatrix}$	$\begin{Bmatrix} 15114 \text{ ML} \\ 14895 \text{ ML} \end{Bmatrix}$
Weather and electricity price transition matrices	*See Appendix A3 in Chapter 3*	
Carbon market starting price ($/MWh)	c_0	$41.11
Accreditation per unit of hydroelectricity generated	θ^c	0.5
Scaling parameter for the water demand/marginal benefit function	$\gamma = \begin{Bmatrix} \gamma_{\phi=1,\ d} & \gamma_{\phi=1,\ n} & \gamma_{\phi=1,\ w} \\ \gamma_{\phi=2,\ d} & \gamma_{\phi=2,\ n} & \gamma_{\phi=2,\ w} \end{Bmatrix}$	$\begin{Bmatrix} 952477 & 746125 & 503291 \\ 960030 & 735314 & 500033 \end{Bmatrix}$
Choke price for irrigation water ($/ML)	p_{CHOKE}	$611
Choke volume for irrigation extraction (ML by weather/season)	$\tilde{\iota}_{CHOKE} = \begin{Bmatrix} \tilde{\iota}_{CHOKE_{\phi=1,d}} & \tilde{\iota}_{CHOKE_{\phi=1,n}} & \tilde{\iota}_{CHOKE_{\phi=1,w}} \\ \tilde{\iota}_{CHOKE_{\phi=2,d}} & \tilde{\iota}_{CHOKE_{\phi=2,n}} & \tilde{\iota}_{CHOKE_{\phi=2,w}} \end{Bmatrix}$	$\begin{Bmatrix} 5274 \text{ ML} & 4131 \text{ ML} & 2787 \text{ ML} \\ 5316 \text{ ML} & 4072 \text{ ML} & 2769 \text{ ML} \end{Bmatrix}$
Number of time periods	t	20 seasons (10 years)
Initial reservoir volume	S_0	310000 ML
Discount factor (per seasonal time-step)	ρ	0.015
Ratio of electricity purchase cost to the electricity price level	ψ	1.27
Maximum/Minimum volume of electricity supply per season	e_{MAX}, e_{MIN}	124585 MWh, 37375 MWh
Probability of electricity purchases (Price Stability Tariff)	ω	0.05

Table 5.1. Summary of parameters for recalibration of the model to Arthurs Lake.

5.4. Results

5.4.1. Water Allocation and Benefits under Alternative Tariffs

I calculate the net benefits of water allocation under the three alternative water tariffs:

(i) Standard Volumetric (SV) Tariff – A water price for irrigation water extractions in period t equal to the marginal revenue of hydroelectricity generation in period t;

(ii) Price Stability (PS) Tariff – A volumetric water price that is the average of the marginal revenue of hydroelectricity generation across periods t, $t-1$, and $t-2$, plus a fixed water scarcity premium;

(iii) Marginal User Cost (MUC) Tariff – The main component of the period t water tariff is the expected marginal revenue of hydroelectricity generation in period $t+1$. Expected marginal revenue in period $t+1$ is determined by the period t electricity price level and the associated probabilities of alternative price levels occurring in period $t+1$. If the expected volume of period $t+1$ reservoir storage is insufficient to fully supply minimum electricity generation, then a scarcity premium is applied to reflect the expected cost of the hydropower company purchasing electricity in period $t+1$.

Replicating the method used in Chapter 4, I conduct 1000 random simulations of the three water tariff scenarios. The sequence of stochastic shifts in the weather, electricity price, and random inflow shocks are the same in each simulation, i.e. for simulation j the time paths of the various state variables (e.g. A_t, B_t, L_t, K_t), the random inflow shock, ε_t, and inflows, $\tilde{f}_t$, are the same across the different scenarios. I calculate the average net present value (NPV) of hydropower benefits, irrigation benefits, total benefits, and electricity purchases for each period within each simulation across the scenarios. The average volume of water extractions, hydroelectricity generation, and electricity purchases is also calculated.

The presentation of the results focuses on the differences between the PS Tariff and the MUC Tariff. Specifically, I concentrate on four costs associated with deploying price stability controls instead of the marginal user cost approach: (i) foregone hydropower benefits; (ii) foregone hydropower generation; (iii) additional cost to the hydropower operator of purchasing electricity to meet supply shortfalls; and (iv) reduced efficiency of overall water use. I also calculate the indirect subsidy to irrigators that is generated by price stability controls. The SV Tariff is the same as the water pricing scenario in Chapter 4 and its inclusion in this analysis shows how that basic tariff design can be improved by incorporating marginal user cost.

Tariff	Hydropower					Irrigation		Total
	Average water extractions (St. dev.)	Average NPV benefits (St. dev.) $ millions	Electricity generation GWh	Electricity purchases GWh	Average NPV of cost of electricity purchases $ millions	Average water extractions (St. dev.)	Average NPV benefits (St. dev.) $ millions	Average NPV benefits (St. dev.) $ millions
Standard Volumetric	474.7 GL (72.4 GL)	$83.3 ($14.6)	900.4 (137.3)	215.5 (51.3)	$12.9 ($4.0)	266.8 GL (23.0 GL)	$52.8 ($4.0)	$136.1 ($11.6)
Price Stability	481.0 GL (72.0 GL)	$84.8 ($14.9)	912.4 (136.6)	204.8 (51.6)	$12.3 ($4.0)	257.7 GL (23.7 GL)	$52.1 ($4.0)	$136.9 ($11.8)
Marginal User Cost	492.2 GL (67.4 GL)	$91.5 ($13.5)	933.6 (127.9)	172.9 (54.9)	$10.5 ($4.3)	236.4 GL (14.6 GL)	$49.1 ($2.7)	$140.6 ($11.5)

Table 5.2. Aggregate model results across water tariff scenarios. Averages reported for 1000 simulations. Each simulation experiences the same stochastic variations across periods as the corresponding simulation in a different scenario. The simulations span 20 seasons (10 years).

Table 5.2 summarises the results for the three water tariff scenarios with a minimum electricity supply requirement equivalent to 30% of the technical maximum hydroelectricity generation production per season, 37.4 GWh. Comparing the average results from the PS Tariff and MUC Tariff across the 10-year simulation period, the average cost of imposing price stability controls from foregone hydropower profits is $6.6 million, or 7.3% of profits under the MUC Tariff. Similarly, hydroelectricity generation is 21.2 GWh, or 2.3%, lower under the PS Tariff. The additional costs of purchasing, on average, an additional 31.9 GWh of electricity under the PS Tariff are $1.8 million. The protection from price fluctuations and a dynamic water scarcity premium means that irrigators receive an indirect subsidy of $3 million, or 6.1% higher benefits, under price stability controls compared to the MUC Tariff. But the resulting reallocation of water from hydropower to irrigation is inefficient: the average cost of reduced water allocation efficiency under the PS Tariff is $3.7 million, or 2.6% of total benefits under the MUC Tariff. Across all simulations, the average volumetric water price is $144 (SV Tariff), $145 (PS Tariff), and $158 (MUC Tariff). Given the inverse relationship between irrigation water demand and water price, these average water prices are consistent with the relative differences in water extractions and benefits across hydropower and irrigation under the alternative tariffs.

Comparing the PS Tariff to the SV Tariff, the deployment of price stability controls with a fixed water scarcity premium reallocates more water to hydropower generation, such that electricity purchases and irrigation benefits are slightly lower and there is a minor increase in the total benefits of water allocation. Comparing the MUC and SV Tariffs, the opportunity costs of not incorporating marginal user cost into the water tariff and the indirect irrigation subsidy are even higher than under the PS Tariff. Note that, for this primary specification of the model, the storage conditions for irrigation and hydropower extractions and the configuration of the water demand function mean that there is no excess irrigation demand across all simulations for all Tariffs (i.e. there is always enough water for irrigation extractions to continue until the marginal benefit equals the volumetric water price).

Figure 5.A1 in Appendix 5.A1 is a histogram of the cost of price stability controls for individual simulations from the hydropower operator's perspective, i.e. NPV hydropower benefits under the PS Tariff minus NPV hydropower benefits under the MUC Tariff. Figure 5.A2 provides the equivalent histogram for total benefits, or the efficiency of water allocation. Although average hydropower and total benefits are generally higher under the MUC Tariff, that is not the case for all simulations. This is because the MUC Tariff is determined by the expected value of foregone hydropower generation in the next period, but the actual transition of the electricity price and weather are random and cannot be predicted precisely. Neither the PS nor MUC Tariff will perfectly optimise hydropower profits nor the efficiency of water allocation because of this randomness. But, on average, the deployment of the PS Tariff represents a major cost to the hydropower operator and reduces the overall social benefits from multipurpose operations.

The results of an individual simulation provide further insights into the dynamics of the model. Below I consider the results from a simulation where the average costs of deploying the PS Tariff instead of the MUC Tariff are: (i) $8.9 million in foregone hydropower profits; (ii) 22.1 GWh in foregone hydroelectricity generation; (iii) $3.7 million of additional electricity purchases; and (iv) $5.4 million in foregone total benefits. Figure 5.1 displays the timepath of the respective volumetric water prices resulting from the different Tariff structures. The marginal revenue of hydropower generation can take on three different values according to the low, medium, and high electricity price levels. The water scarcity premium comes into force under the MUC Tariff in periods 5, 7, 9, 15, 17, and 19.

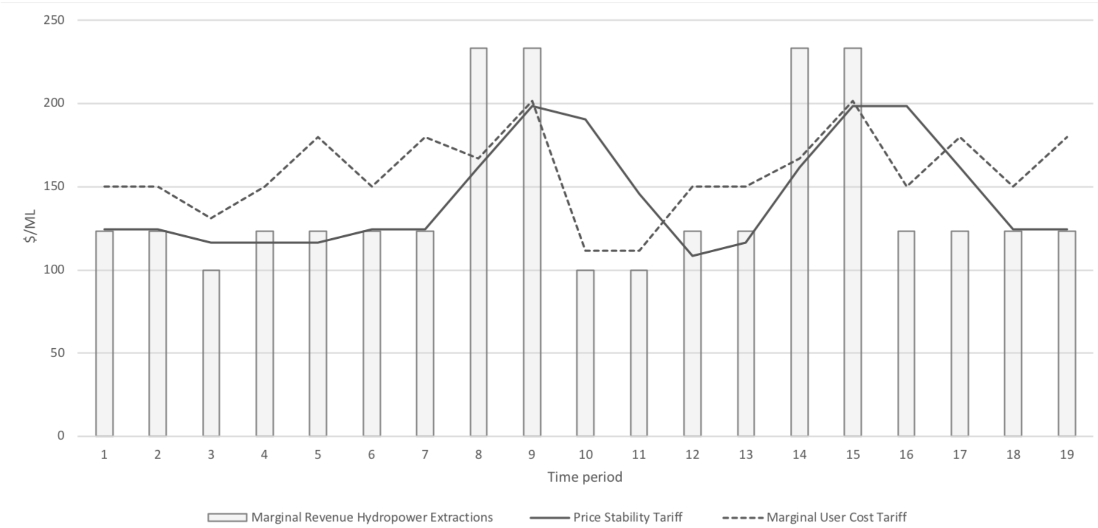

Figure 5.1. Volumetric water price under the PS and MUC Tariffs and the marginal revenue of hydropower generation for a selected simulation.

In the first 7 periods and in periods 12-13, the MUC Tariff is higher than the PS Tariff because the former incorporates the probability of the transition to the highest electricity price level in the next period. Consequently, more water is available for hydropower extractions in periods 6 and 8 under the MUC Tariff. Although the PS Tariff and MUC Tariff are approximately the same as the electricity price transition moves to the highest level in periods 8-9 and 14-15, the MUC Tariff adjusts more quickly to the downward shift in the electricity price, thereby enabling an efficient water reallocation from hydropower to irrigation in periods 10, 11, and 17. This is a somewhat perverse outcome: the price stability tariff, which is designed to protect irrigators from price variability, actually prevents an efficient reallocation of water from hydropower to irrigation.

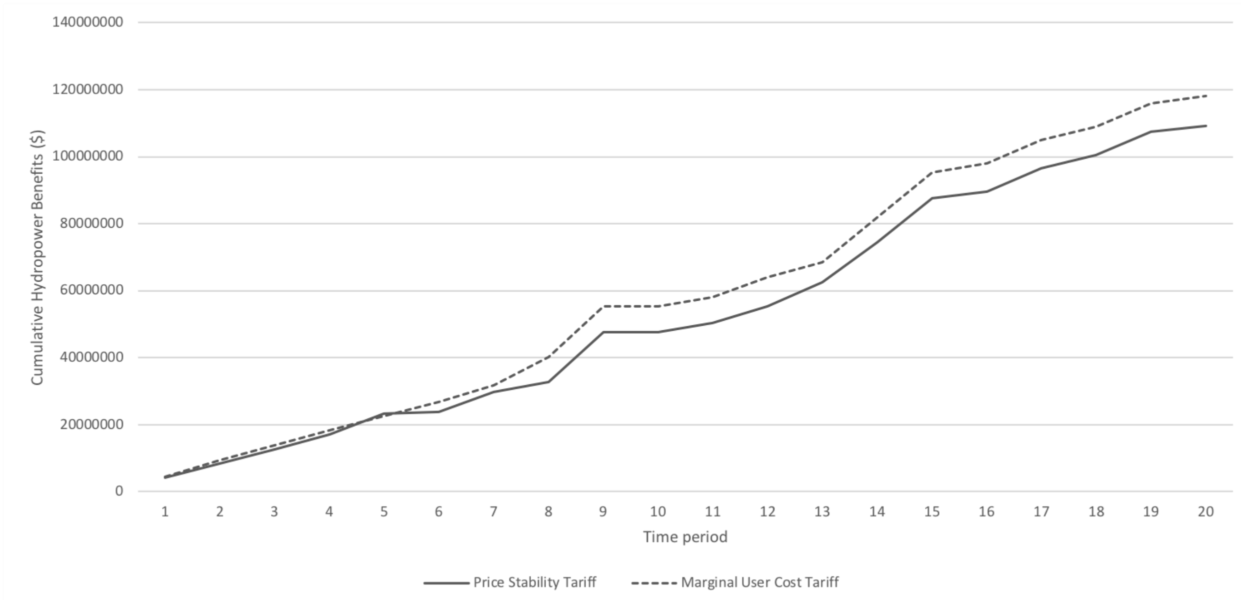

Figure 5.2. Cumulative hydropower profits under the Price Stability Tariff and Marginal User Cost Tariff.

Figure 5.2 demonstrates how cumulative hydropower benefits change over time and Figures 4.3a-4.3d demonstrate the causes of divergences in benefits under the PS and MUC Tariff. Under the PS Tariff, there is insufficient storage available to meet the minimum supply obligation in periods 6, 8, 10, and 16. By contrast, the hydropower operator only needs to purchase electricity under the MUC Tariff in periods 10 and 16; instead of needing to purchase electricity in period 8, the hydropower operator can sell high-value electricity when an electricity price spike occurs. While specific events driving variations in hydropower and total benefits can be readily identified, it is important to note that small differences in hydropower and irrigation extractions accumulate. Overall, the timepath of the reservoir level is very similar, the major difference is how water is allocated between hydropower and irrigation under the different pricing arrangements. This description of the model dynamics for a specific simulation provides insights into the different ways in which the application of price stability controls may, relative to outcomes under the MUC Tariff, generate costs. The specific nature of these costs and why, where, and when they occur varies across different simulations.

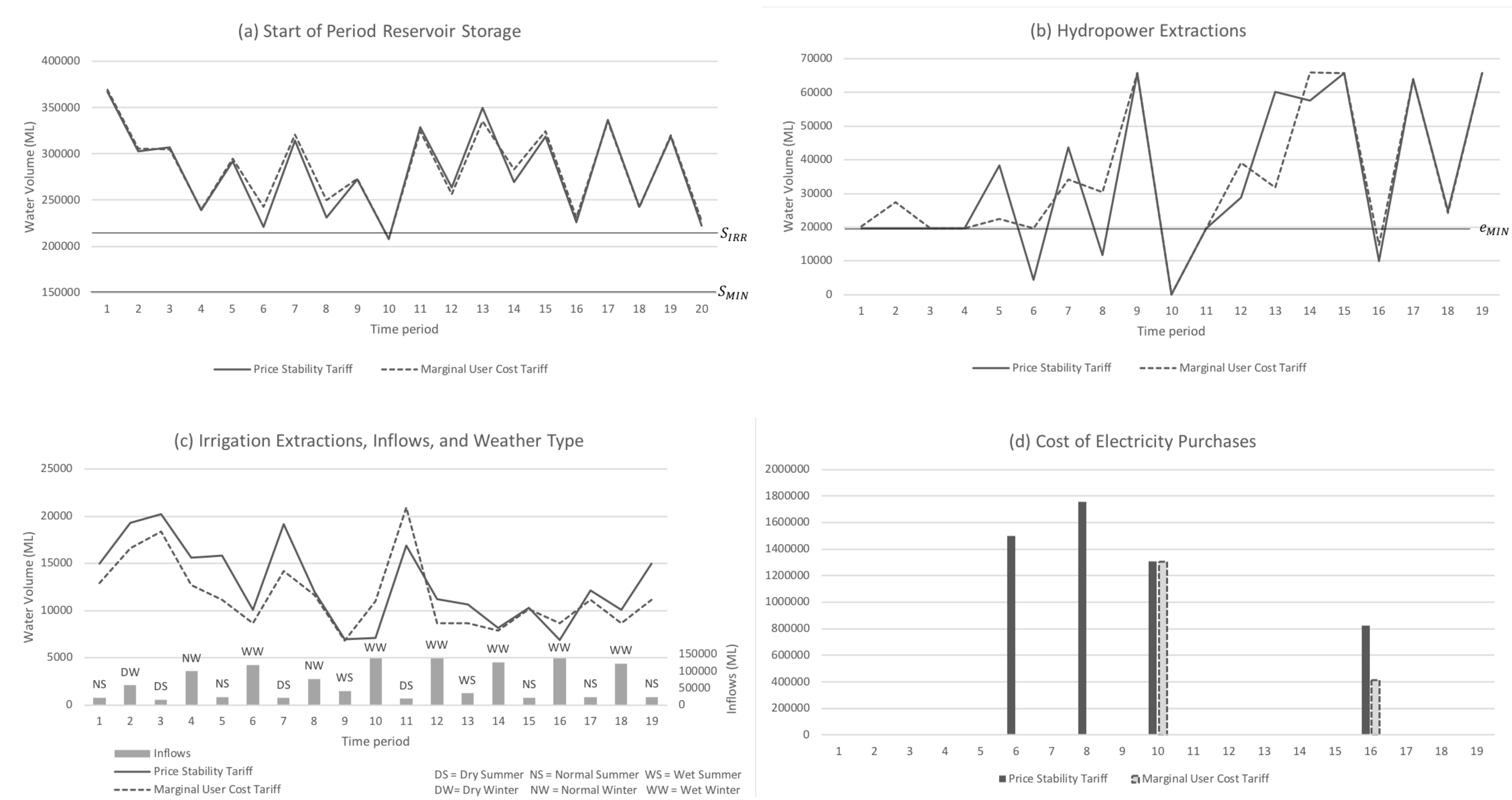

Figure 5.3. Time-path of key variables for a simulation where the Price Stability Control Tariff causes reduced hydropower profits and inefficient water allocation relative to the Marginal User Cost Tariff.

5.4.2. Sensitivity Analysis of the Costs of Price Stability Controls

I conduct a sensitivity analysis of key parameters to derive insights on how the costs of price stability controls change relative to the primary model results reported in Section 5.4.1. A description of the sensitivity analysis for each parameter is provided in Section A.2 of Appendix, including Tables 5.A1-5.A4 for data underlying the values in Table 5.3 below.

Scenario	**Costs of price stability controls**				**Indirect irrigation subsidy**
	Foregone hydropower benefits $ millions	Foregone hydroelectricity generation GWh	Cost of additional electricity purchases $ millions	Reduced efficiency of water allocation $ millions	Additional irrigation profits under PS Tariff $ millions
Primary model	$6.6 (7.3%)	21.2 (2.3%)	$1.8 (17.3%)	$3.6 (2.6%)	$3.0 (6.1%)
Minimum electricity supply obligation					
$\boldsymbol{e_{MIN} = 0}$	$0.50 (0.5%)	5.6 (0.6%)	Not Applicable	$0.8 (0.1%)	$0.6 (1.2%)
$\boldsymbol{e_{MIN} = 10\%}$ **of** $\boldsymbol{e_{MAX}}$	$4.1 (4.2%)	20.9 (2.1%)	$0.7 (17.6%)	$1.4 (1.0%)	$2.7 (5.4%)
$\boldsymbol{e_{MIN} = 50\%}$ **of** $\boldsymbol{e_{MAX}}$	$11.6 (14.1%)	47.1 (13.6%)	$3.2 (13.6%)	$6.7 (5.2%)	$4.9 (10.4%)
$\boldsymbol{e_{MIN} = 70\%}$ **of** $\boldsymbol{e_{MAX}}$	$9.3 (13.8%)	64.3 (6.2%)	$4.0 (9.3%)	$3.0 (2.7%)	$6.2 (13.6%)
Electricity purchase premium					
$\boldsymbol{\psi = 1.16}$	$3.7 (4.1%)	1.0 (0.1%)	$1.7 (15.2%)	$1.3 (1.0%)	$2.3 (4.7%)
$\boldsymbol{\psi = 1.31}$	$4.8 (5.3%)	26.7 (2.9%)	$1.8 (16.5%)	$1.6 (1.1%)	$3.3 (6.7%)
High and medium electricity price level					
$\boldsymbol{L_h = \$67.71}$	$2.50 (3.1%)	9.3 (1.0%)	$1.5 (12.7%)	$0.2 (0.2%)	$2.7 (5.1%)
$\boldsymbol{L_h = \$133.48}$	$6.0 (5.8%)	31.0 (3.3%)	$2.0 (19.6%)	$2.5 (1.7%)	$3.5 (7.5%)
$\boldsymbol{L_m = \$67.71}$	$3.4 (3.2%)	24.8 (2.4%)	$1.0 (6.0%)	$0.5 (0.4%)	$2.9 (6.5%)
Water demand and irrigation storage buffer					
Doubled water demand	$11.3 (12.3%)	77.0 (12.7%)	$3.4 (16.8%)	$2.8 (1.5%)	$8.5 (9.0%)
$\boldsymbol{S_{IRR} = S_{RISK}}$	$2.6 (2.5%)	28.6 (2.66%)	$0.3 (5.3%)	$1.2 (0.8%)	$1.4 (2.9%)
Doubled water demand & $\boldsymbol{S_{IRR} = S_{RISK}}$	$3.1 (3.0%)	-7.7 (0.8%)	$1.4 (9.4%)	$2.3 (1.3%)	$0.8 (1.0%)
Price elasticity of water demand					
$\boldsymbol{\alpha = -0.5}$	$4.0 (4.4%)	24.7 (2.7%)	$0.7 (5.5%)	$0.7 (0.5%)	$3.3 (4.9%)
$\boldsymbol{\alpha = -0.7}$	$5.4 (5.9%)	-16.1 (1.7%)	$3.1 (29.4%)	$2.2 (1.5%)	$3.0 (5.5%)
$\boldsymbol{\alpha = -0.9}$	$4.8 (5.3%)	24.6 (2.6%)	$2.0 (18.8%)	$1.9 (1.4%)	$2.9 (6.5%)

Table 5.3. Average costs of price stability controls and indirect irrigation subsidies under alternative values for key parameters. Percentages are calculated in terms of the total value under the MUC Tariff, e.g. the percentage of foregone hydropower benefits equals $\frac{\text{MUC Tariff hydropower benefits} - \text{PS Tariff hydropower benefits}}{\text{MUC Tariff hydropower benefits}}$. The relevant parameters for the primary model are $e_{MIN} = 30\%$ of e_{MAX}, $\psi = 1.27$, $L_h = \$102.31$, $\alpha = -0.81$.

Overall, the costs of foregone hydropower benefits are generally higher (lower) for higher (lower) values of the electricity supply obligation and when irrigation water demand is higher. Although the relative benefits of marginal user cost tariffs are not substantial if there is no electricity supply obligation, they are consistently evident across the various parameter specifications. Notwithstanding some exceptions, there are generally costs in terms of foregone generation, particularly for high levels of the electricity supply obligation, the electricity purchase premium, electricity price level, and irrigation water demand. Variations in the cost of additional electricity purchases broadly move in sync with foregone hydropower benefits. For all specifications where there is an electricity supply obligation, the size of the indirect subsidy to irrigation under the PS Tariff is consistently less than foregone hydropower benefits and, hence, water is allocated inefficiently. However, the efficiency loss is generally less than under the primary model.

The overall result of imposing price stability controls is an increase in irrigator profits through inefficient water allocation. Although this result is generally due to reduced hydropower profits, there is one model specification where a substantial component of inefficiency in water allocation is due to excess irrigation water demand. If irrigation of water demand is doubled and the irrigation storage buffer is removed, the PS Tariff leads, on average and compared to the MUC Tariff, to excess irrigation water demand of an additional 35 GL (see Table 5.A3 in Appendix). This translates into foregone irrigation benefits of \$25.7 million under the PS Tariff compared to \$20 million under the MUC Tariff. Overall irrigation benefits remain higher under the PS Tariff, but the relative benefits accruing to irrigators of price stability controls become less than \$1 million. This demonstrates that, as irrigation water demand increases and water becomes scarcer, trade-offs can also emerge between period t and period $t + 1$ irrigation extractions under inefficient pricing. Even though our specification of marginal user cost is focused on the costs of water scarcity borne by the hydropower company, scarcity-based pricing can also provide irrigators with incentives to reduce the incidence of their own excess water demand.

Appendix 5.A2 also reports results for the SV Tariff across the various parameter specifications in Table 5.3. Comparing the SV and MUC Tariffs, both hydropower benefits and the total efficiency of water allocation are consistently higher under the latter approach.

5.5. Discussion

(i) Price stability controls generate private and social costs when hydropower operators have an electricity supply obligation and/or water availability for hydropower generation is constrained

Section 5.4 shows how price stability controls reallocate water and benefits to irrigators when there are opportunity costs from hydropower generation falling below a threshold. Importantly, the indirect subsidy resulting from the PS Tariff is not costless. Foregone hydropower profits and generation are not just private costs borne by hydropower companies; if those companies are state-owned then lower revenues will either reduce dividends to the government or necessitate government expenditure to maintain their financial sustainability. Both of these outcomes would detract from government spending in other sectors, such as health and education.

In many electricity systems, hydropower will increasingly play a key role in: (i) providing firming capacity for solar and wind generation, and/or (ii) addressing burgeoning electricity demand. In the absence of these energy services, the gap will be filled by electricity imports from neighboring markets or generation from alternative sources (such as natural gas and diesel), with the additional costs passed through to consumers in the form of higher electricity prices. The relative inefficiency in water allocation of 1-2% estimated for the particular reservoir modelled here may not seem a major concern at first glance, but, in practice, these costs would escalate under supply variability, as additional sources of demand compete for scarce water, or when inefficient practices perpetuate across multiple reservoirs and water catchments. Further, I have only estimated here the distortions arising from misallocating water with a water price averaged over 3 years; extending that approach to 5 or 10 years could exacerbate those distortions even further.

Regulators need to account for social preferences and externalities from irrigated agriculture (that were not modelled in this study) when deciding whether price stability controls are appropriate elements of water tariff design for multipurpose reservoirs. However, price controls do not come for free and subsiding irrigators using this method would imposes externalities on hydropower companies and, potentially, businesses and households that are not directly affected by reservoir operations and their governance. If policy-makers seek to further the capacity for hydropower reservoirs to provide water services through water pricing, then hydropower companies need to, at minimum, be compensated for the approximate value of their foregone generation. Unless the user cost of water services provision is incorporated into dynamic water tariffs, water pricing will not provide sufficient incentives for hydropower companies to invest in multipurpose infrastructure or flexibly provide water services beyond those mandated by command-and-control regulation.

(ii) *Incorporating marginal user costs into water tariff design is practically achievable and increases the efficiency of water allocation*

In this Chapter, I estimate marginal user cost with a heuristic that leads to a more efficient water allocation compared to either the SV or PS Tariff. For hydropower, there are certain cases where the marginal user cost could be calculated even more accurately using this method, e.g. where forward electricity prices are known two seasons in advance, future electricity prices are regulated, or there are financial contracts available. On the other hand, there may be situations where our key assumption, that the opportunity cost of extracting a unit of water for irrigation is equal to the marginal value of foregone hydropower generation in the next period, is less applicable. Where there are in-situ benefits from additional water storage, such as improved reservoir water quality, or there are multiple types of variable water extraction, then the value of holding additional supply may extend several periods into the future. In these last two cases, the practical benefits of the heuristic approach may be outweighed by imprecision and the model-based calculation is preferable. Nevertheless, I have shown that is it not necessary to use stochastic dynamic programming or other modelling techniques to estimate marginal user cost and beneficially incorporate it into water tariff design. The heuristic I outline here could be adapted to other applications, such as urban water systems, and enable regulators to implement dynamic water tariffs in a manner that is understandable and transparent for all stakeholders.

(iii) *Price stability controls on irrigation water pricing could prevent efficient water reallocation from hydropower to irrigation and generate intertemporal opportunity costs for irrigators*

In this study I have primarily focused on the trade-offs between irrigation benefits and hydropower benefits. The results of the specific simulation described in Section 5.4.1 show how price stability controls create lags in the impact of both upward and downward shifts in electricity prices on the volumetric water price that irrigators pay. Constraints on efficient water reallocation generate social welfare losses regardless of the direction of unrealised transfers. From the perspective of irrigators, however, price stability controls suppressing cheaper water prices is a private loss. In the sensitivity analysis of the water demand specification and the irrigation storage buffer, it is shown that price stability controls can cause a greater volume of excess irrigation water demand relative to the MUC Tariff. This is a perverse outcome: pricing controls intended to benefit irrigators can actually undermine their welfare by inefficiently allocating water across time periods. Whilst the effect of lagged downward price shifts and the volume of excess water demand may depend on the number of periods over which the water price is averaged, these factors highlight that price stability controls could actually deliver limited welfare benefits to irrigators in some cases.

(iv) *One policy instrument for one policy objective is a useful principle for pricing irrigation extractions from multipurpose hydropower reservoirs*

In a review of the limitations of Increasing Block Tariffs for urban water pricing, Young and Whittington (2016) cite the work of Tinbergen (1952) to argue that equity objectives should be addressed through separate policies. The Tinbergen Principle of one policy instrument for one policy objective similarly applies here. I have shown in this Chapter how price stability controls are a blunt instrument that inefficiently imposes costs on hydropower operators, society, and, in certain situations, does not doing a particularly good job of increasing irrigators welfare under water price spikes. A preferable approach would be to complement efficient water tariff design with separate measures that address negative impacts on irrigators' welfare from higher or more variable water prices. For example, redistributing part of the additional benefits that the hydropower operator receives under the efficient marginal user cost tariff towards: (i) cash transfers to farmers when water prices become high, (ii) reductions on the fixed costs of within-scheme water prices, or (iii) the provision of extension services, finance for regional infrastructure, and any other scheme that supports farmers' welfare and agricultural productivity. Provided these measures did not increase irrigation water demand, then water would still be allocated more efficiently. Ultimately, water pricing is about the efficient and sustainable provision of a scarce resource. Other priorities, such as equity, are just as if not more worthy goals of water policy and regulation: the point is that they could and should be addressed through targeted measures that do not distort water allocation and generate private and social costs.

4.6. Conclusion

There is great scope for water pricing to regulate the provision of irrigation water services by hydropower reservoirs. But, as in other areas of water management, realising the potential benefits of price-based water allocation is contingent on tariff design. In this Chapter, I have shown how price stability controls can inefficiently subsidise irrigation water provision, and that these subsidies impose private and social costs when hydropower operation is constrained by electricity supply obligations. I have also outlined a transparent approach to calculating marginal user cost and its incorporation into water tariffs. Both of these contributions provide guidance for future applications of water pricing to hydropower governance.

A number of limitations of this study provide directions for future research. I have not considered stochastic or deterministic changes in the cost or penalty of a hydropower operator purchasing electricity to meet their supply obligations. Similarly, the specification of the electricity price considers only three levels, and there is scope to subject the final electricity price to a random shock in the same way that a given weather state can lead to a range of reservoir inflows (see full model description in Section 4.2 of Chapter 4). I have assumed that hydroelectricity is sold in a forward market while, in practice, hydropower operators derive revenue from spot markets and a variety of different products in contract markets. I have used an averaging approach to implementing price stability controls because that is the method used in the location to which the model is calibrated. Other options to control prices could include caps, floors, or a combination thereof in the form of a price collar. I have highlighted that targeted, non-price measures would be a more efficient method of supporting irrigators than price controls, but have not modelled a specific measure here. All of the above matters warrant further study and consideration for other multipurpose hydropower reservoirs and regulatory contexts. Finally, the heuristic I have outlined for estimating marginal user cost needs to be adapted and tested for other applications, such as urban water provision and within-scheme irrigation water pricing, in order to understand the broader utility of the approach.

Appendix 5.A1. The Costs of Price Stability Controls Across Simulations

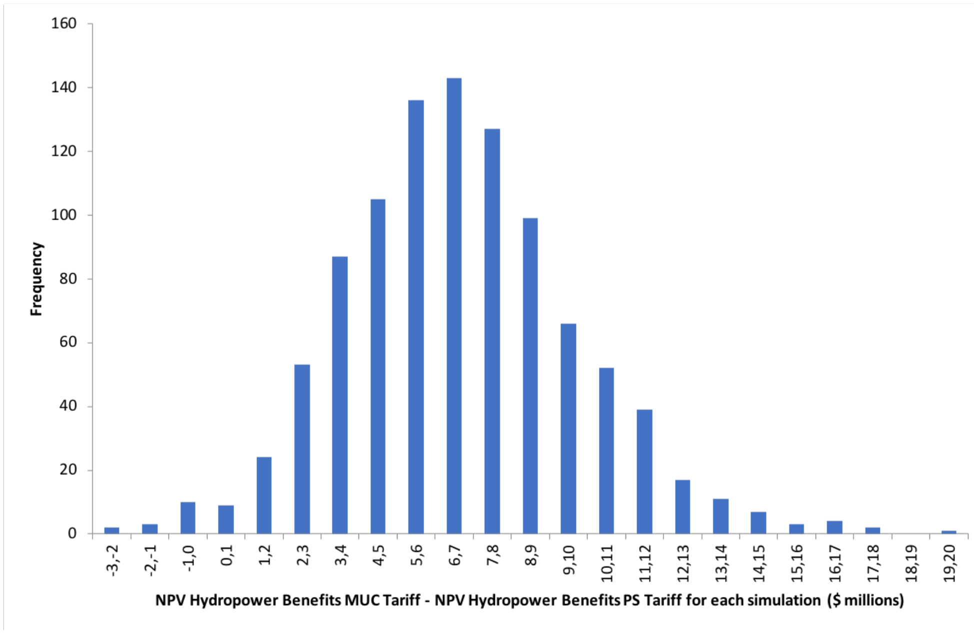

Figure 5.A1. Histogram of the cost of price stability controls from foregone hydropower revenue across individual simulations for the primary model.

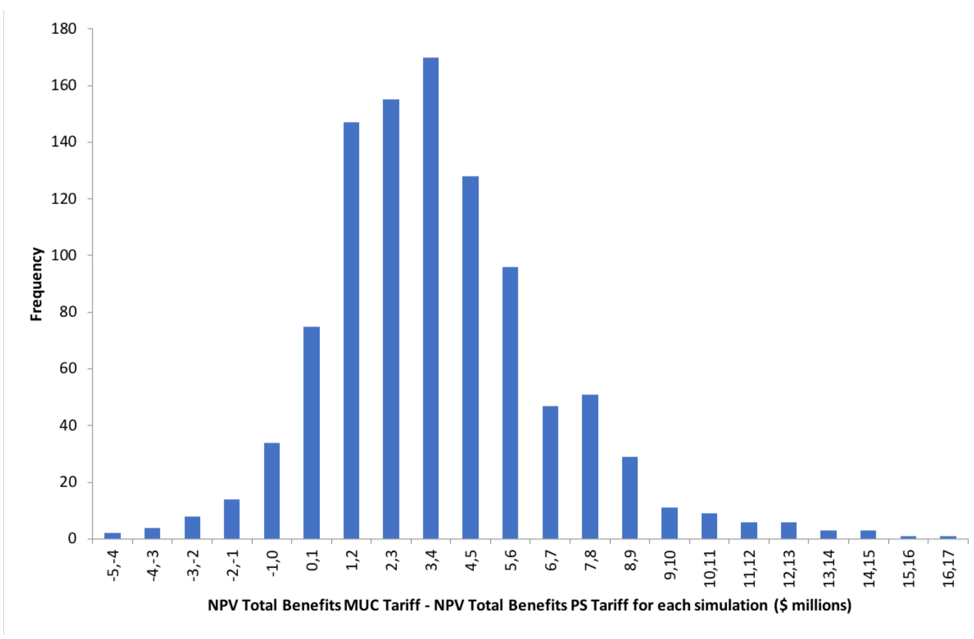

Figure 5.A2. Histogram of the cost of price stability controls from inefficiently allocating water between hydropower and irrigation across individual simulations for the primary model.

Appendix 5.A2. Complete Results of the Sensitivity Analysis

Minimum electricity supply requirement

Alternative specifications of the minimum electricity supply requirement are considered. Table 5.A1 shows how the results change if the supply obligation is lower (0% and 10%) or higher (50% or 70%). Overall, the average costs of price stability controls (i.e. foregone hydropower profits, foregone hydroelectricity generation, additional electricity purchases, and foregone total benefits) are generally higher (lower) for higher (lower) electricity supply requirements.

Tariff	Hydropower					Irrigation		Total
	Average water extractions GL	Average NPV benefits $ millions	Electricity generation GWh	Electricity purchases GWh	Average NPV of cost of electricity purchases $ millions	Average water extractions GL	Average NPV benefits $ millions	Average NPV benefits $ millions
$\boldsymbol{e_{MIN} = 0}$								
SV	499.1	$96.6	946.7	NA	NA	266.8	$52.8	$149.4
PS	509.3	$98.1	966.0	NA	NA	257.7	$52.1	$150.0
MUC	512.2	$98.6	971.6	NA	NA	250.9	$51.5	$150.1
$\boldsymbol{e_{MIN} = 10}$% of $\boldsymbol{e_{MAX}}$								
SV	496.7	$92.9	942.1	73.8	$4.5	266.8	$52.8	$145.4
PS	503.6	$93.3	955.0	70.9	$4.3	257.7	$52.1	$145.4
MUC	514.5	$97.4	975.9	59.5	$3.7	238.6	$49.4	$146.8
Primary model ($\boldsymbol{e_{MIN} = 30}$% of $\boldsymbol{e_{MAX}}$)								
SV	474.7	$83.3	900.4	215.5	$12.9	266.8	$52.8	$136.1
PS	481.0	$84.8	912.4	204.8	$12.3	257.7	$52.1	$136.9
MUC	492.2	$91.5	933.6	172.9	$10.5	236.4	$49.1	$140.6
$\boldsymbol{e_{MIN} = 50}$% of $\boldsymbol{e_{MAX}}$								
SV	489.7	$73.3	928.8	464.4	$27.7	266.8	$52.8	$126.1
PS	496.0	$70.9	940.8	444.9	$26.8	257.7	$52.1	$123.0
MUC	520.9	$82.5	988.0	392.0	$23.6	224.6	$47.2	$129.7
$\boldsymbol{e_{MIN} = 70}$% of $\boldsymbol{e_{MAX}}$								
SV	502.0	$56.1	952.1	803.6	$48.1	266.8	$52.8	$109.1
PS	509.2	$58.1	965.9	749.0	$47.2	257.7	$52.1	$110.2
MUC	543.1	$67.3	1030.2	718.9	$43.2	217.5	$45.9	$113.2

Table 4.A1. Sensitivity analysis of the minimum electricity supply obligation.

Electricity purchase premium and high/medium electricity price level

Alternatives to the electricity purchase premium are calculated on the basis of the 25th percentile ($\psi = 1.16$) and 75th percentile ($\psi = 1.31$) for the average percentage difference between the monthly peak and average spot price for the Victorian NEM market from 1999-2016. The high price level for the original specification used in Chapter 4 ($L_h = \$67.71$) is calculated using long-term averages. I also consider the highest average wholesale spot market price during Q1 2018 ($L_h = \$133.48$) and a higher medium electricity price level ($L_h = \$67.71$).

Tariff	Hydropower					Irrigation		Total
	Average water extractions GL	Average NPV benefits \$ millions	Electricity generation GWh	Electricity purchases GWh	Average NPV electricity purchases \$ millions	Average water extractions GL	Average NPV benefits \$ millions	Average NPV benefits \$ millions
Primary Model ($\psi = 1.27$, $L_h = \$102.31, L_m = \$44.40$)								
SV	474.7	\$83.3	900.4	215.5	\$12.9	266.8	\$52.8	\$136.1
PS	481.0	\$84.8	912.4	204.8	\$12.3	257.7	\$52.1	\$136.9
MUC	492.2	\$91.5	933.6	172.9	\$10.5	236.4	\$49.1	\$140.6
$\psi = 1.16$								
SV	492.8	\$85.5	934.7	242.8	\$13.4	266.8	\$52.8	\$138.3
PS	498.3	\$86.8	945.2	229.9	\$12.8	258.5	\$52.2	\$139.0
MUC	498.8	\$90.5	946.1	199.6	\$11.1	240.9	\$49.9	\$140.4
$\psi = 1.31$								
SV	475.7	\$85.0	902.3	217.3	\$13.4	266.8	\$52.8	\$137.8
PS	479.4	\$86.6	909.3	202.6	\$12.6	257.4	\$52.1	\$138.7
MUC	493.4	\$91.4	936.0	173.0	\$10.8	233.7	\$48.8	\$140.2
$L_h = \$67.71$								
SV	488.6	\$76.3	926.9	263.6	\$13.4	279.4	\$55.4	\$131.8
PS	492.9	\$77.1	935.0	259.1	\$13.2	274.6	\$55.0	\$132.1
MUC	497.9	\$79.6	944.3	230.2	\$11.7	255.2	\$52.3	\$131.9
$L_h = \$133.48$								
SV	471.7	\$94.6	894.7	201.4	\$13.6	260.0	\$50.9	\$145.5
PS	478.7	\$97.2	908.0	181.5	\$12.5	246.6	\$49.9	\$147.1
MUC	495.1	\$103.2	939.1	149.6	\$10.4	222.1	\$46.4	\$149.5
$L_m = \$67.71$								
SV	529.3	\$99.4	1003.9	243.7	\$17.9	233.8	\$47.7	\$147.1
PS	535.9	\$101.2	1016.5	232.3	\$17.2	224.6	\$46.9	\$148.1
MUC	549.0	\$104.6	1041.3	217.9	\$16.3	207.3	\$44.0	\$148.6

Table 5.A2. Sensitivity analysis of the electricity purchase price premium and the specification of the high and medium electricity price levels.

Water demand and irrigation storage buffer

The scaling parameter of the water demand function (γ) is doubled for all weather/season pairs so that: (i) irrigation water demand is doubled for each period of every simulation and, (ii) the irrigation choke volume ($\tilde{\iota}_{CHOKE}$) value is doubled. Formally, this means that

$$\gamma = \begin{Bmatrix} \gamma_{\phi=1,\ d} & \gamma_{\phi=1,\ n} & \gamma_{\phi=1,\ w} \\ \gamma_{\phi=2,\ d} & \gamma_{\phi=2,\ n} & \gamma_{\phi=2,\ w} \end{Bmatrix} = \begin{Bmatrix} 952477 & 746125 & 503291 \\ 960030 & 735314 & 500033 \end{Bmatrix}, \tilde{\iota}_{CHOKE} = \begin{Bmatrix} \tilde{\iota}_{CHOKE_{\phi=1,d}} & \tilde{\iota}_{CHOKE_{\phi=1,n}} & \tilde{\iota}_{CHOKE_{\phi=1,w}} \\ \tilde{\iota}_{CHOKE_{\phi=2,d}} & \tilde{\iota}_{CHOKE_{\phi=2,n}} & \tilde{\iota}_{CHOKE_{\phi=2,w}} \end{Bmatrix} = \begin{Bmatrix} 5274\text{ ML} & 4131\text{ ML} & 2787\text{ ML} \\ 5316\text{ ML} & 4072\text{ ML} & 2769\text{ ML} \end{Bmatrix}$$

Tariff	Hydropower					Irrigation				Total
	Average water extractions GL	Average NPV benefits $ millions	Electricity generation GWh	Electricity purchases GWh	Average NPV of cost of electricity purchases $ millions	Average water extractions GL	Average NPV benefits $ millions	Excess irrigation water demand GL	Average NPV of cost of excess water demand $ millions	Average NPV benefits $ millions
Primary model ($S_{IRR} > S_{RISK}$)										
SV	474.7	$83.3	900.4	215.5	$12.9	266.8	$52.8	0	Not applicable	$136.1
PS	481.0	$84.8	912.4	204.8	$12.3	257.7	$52.1	0	Not applicable	$136.9
MUC	492.2	$91.5	933.6	172.9	$10.5	236.4	$49.1	0	Not applicable	$140.6
Doubled water demand										
SV	267.0	$78.9	506.5	406.3	$24.0	513.2	$103.8	20.29	$2.1	$182.7
PS	278.0	$81.0	527.3	397.5	$23.6	499.5	$102.9	15.9	$1.7	$183.9
MUC	318.6	$92.3	604.3	342.8	$20.2	447.0	$94.4	4.0	$0.3	$186.7
$S_{IRR} = S_{RISK}$										
SV	555.4	$100.5	1053.4	126.3	$6.8	238.2	$48.3	28.6	$5.7	$148.8
PS	551.7	$101.3	1046.4	113.6	$6.1	233.3	$48.2	24.4	$3.9	$149.5
MUC	566.7	$103.9	1075.0	108.3	$5.8	223.2	$46.8	19.8	$3.4	$150.8
Doubled water demand & $S_{IRR} = S_{RISK}$										
SV	481.3	$97.3	913.0	279.5	$16.1	372.3	$79.5	158.4	$31.8	$176.8
PS	489.3	$98.2	928.1	286.5	$16.5	364.8	$78.6	150.5	$25.7	$176.8
MUC	485.3	$101.3	920.5	266.4	$15.1	359.2	$77.8	114.4	$20.7	$179.0

Table 5.A3. Sensitivity analysis of water demand and the irrigation storage buffer.

Price elasticity of irrigation water demand

As highlighted in Chapter 3, the price elasticity of demand (α) defines the slope of the marginal benefit function for irrigation water demand. The value used above (α = -0.81) implies that the demand for water decreases by 0.81% for every 1% increase in price. A lower value (i.e. α = -0.9) indicates the marginal benefit function has a flatter slope and lower choke water volume for a given weather/season state. Conversely, a higher value (i.e. α = -0.5, -0.7) indicates a steeper slope and higher choke volume. These changes affect the volume of irrigation water demand and, consequently, the volume of water available for hydroelectricity generation.

Tariff	**Hydropower**					**Irrigation**		**Total**
	Average water extractions GL	Average NPV benefits $ millions	Electricity generation GWh	Electricity purchases GWh	Average NPV of cost of electricity purchases $ millions	Average water extractions GL	Average NPV benefits $ millions	Average NPV benefits $ millions
$\boldsymbol{\alpha = -0.5}$								
SV	469.0	$86.3	889.7	211.8	$12.7	270.9	$69.7	$156.1
PS	472.6	$87.3	896.5	206.7	$12.5	265.9	$69.3	$156.6
MUC	485.7	$91.3	921.2	194.1	$11.8	251.6	$66.0	$157.3
$\boldsymbol{\alpha = -0.7}$								
SV	473.2	$85.5	897.5	216.9	$13.0	268.0	$58.1	$143.6
PS	495.8	$86.2	940.5	227.8	$13.8	260.4	$57.5	$143.8
MUC	487.4	$91.6	924.4	176.3	$10.7	241.7	$54.5	$146.0
$\boldsymbol{\alpha = -0.81}$ **(Primary model)**								
SV	474.7	$83.3	900.4	215.5	$12.9	266.8	$52.8	$136.1
PS	481.0	$84.8	912.4	204.8	$12.3	257.7	$52.1	$136.9
MUC	492.2	$91.5	933.6	172.9	$10.5	236.4	$49.1	$140.6
$\boldsymbol{\alpha = -0.9}$								
SV	475.9	$85.2	902.7	217.5	$13.0	266.0	$48.9	$134.1
PS	482.7	$86.5	915.6	206.8	$12.5	255.5	$48.1	$134.6
MUC	495.7	$91.3	940.2	171.5	$10.5	232.2	$45.2	$136.5

Table 5.A4. Sensitivity analysis of the price elasticity of water demand.

Chapter 6

Conclusion

6.1. Summary

This thesis examines the economics and governance of multipurpose hydropower reservoirs from macro-level concepts to how research can be incorporated into decision-making and the design of a specific regulatory reform. It addresses the following research questions (previously stated in Chapter 1):

a) What hydropower governance reforms could enable multipurpose operations under risks?
b) How can applied research on water governance reforms be integrated into real-world decision-making?
c) When does water pricing allocate water more efficiently than fixed irrigation quotas under risks?
d) What is the optimal design of irrigation water tariffs for hydropower governance in the presence of an electricity supply obligation and electricity price spikes?

Chapter 2 addresses (a) by proposing three reforms that could enable the sustainable provision of water services through dynamic water reallocation: (i) periodic relicensing, (ii) water pricing, and (iii) climate/green performance bonds. Chapter 3 addresses (b) by providing insights on the use of participatory modelling tools to conduct policy-focused risk assessments, including: the transfer of knowledge and information, establishing the credibility of the participatory process, and balancing reductionism and completeness. Chapter 4 addresses (c) through hydro-economic modelling, finding that water pricing allocates water more efficiently under shifting water demand, water scarcity, and level effects in hydroelectricity revenues. On the other hand, fixed quotas may be sufficient for multipurpose hydropower regulation where: (i) they provide a central estimate of the shifting demand for and opportunity cost of water services; or (ii) they can be updated to reflect dynamic changes in the value of water and energy services, e.g. through periodic relicensing. Chapter 5 addresses (d) by showing how price stability controls indirectly subsidise irrigation water provision and impose private and social costs when the flexibility of hydropower operation is constrained by electricity supply obligations. By contrast, a water tariff that incorporates the intertemporal opportunity costs of water services provision allocates water more efficiently and, importantly, provides profit-motivated hydropower companies with greater discretion to provide water services under electricity market risks.

The contributions of the thesis to the academic literature include:

- Demonstrating that the resilience of multipurpose hydropower reservoirs to risks is dependent on the capability of water governance instruments to dynamically reallocate water;
- Designing and conducting the first, field-based application of a participatory risk assessment process developed by an international network of researchers and practitioners;
- Conducting the first hydro-economic modelling and analysis of the application of water pricing to hydropower regulation;
- Conducting the first hydro-economic modelling and analysis of alternative water tariff designs for hydropower regulation;
- Developing and demonstrating a heuristic for incorporating marginal user cost into water tariffs that is applicable to water management problems where large opportunity costs accrue beyond threshold levels of storage.

6.2. Implications of the Research

This research reframes the regulation of multipurpose hydropower operations as the resolution of trade-offs through dynamic reallocation of water. I show that the shifting values of energy and water services mean that hydropower companies require flexible regulation to support the resilience of connected water systems. Ultimately, broad-scale shifts in perceptions and preferences may be needed for hydropower reservoirs to promote water security, contribute to climate change adaptation, and consistently deliver non-energy benefits to societies. Simply assuming that built water infrastructure will consistently deliver benefits is a flawed perspective, particularly given the complexity and magnitude of the risks emerging from climate change and the renewable energy transition. Absent flexible regulation, new multipurpose hydropower projects could become sources of instability in social-ecological systems.

The vision of sustainable, multipurpose hydropower development may only be realised if profit-motivated hydropower companies can generate revenue across a portfolio of energy and water services. In short, transitioning to being water managers that generate electricity. Financial incentives from water pricing could be supported by dynamic operating constraints to provide hydropower companies with the discretion to reallocate water for both public and private benefit. Implementing these regulatory innovations would require a major cultural change across the hydropower industry, water users, and regulatory agencies. And there would be many policy design and implementation challenges to overcome. But the necessary change could begin by developing and testing the reforms proposed here through participatory research with those stakeholders.

6.3. Future Work

Each chapter of this thesis provides a summary of limitations and prospects for future work. Here, I develop the main ideas further and explain how they could be developed into research projects.

Climate/green performance bonds for water infrastructure

Further development of the climate/green performance bonds outlined in Chapter 3 would require a number of key research steps. First, a formal mathematical derivation that examines alternative design features, such as the variable interest rate being determined by input or output based metrics (e.g. the volume of water delivered to farmers versus farmer's water security), and identifies the likely implementation barriers, such as the size of the variable interest rate spread. Second, further research into the relevant features of similar financial instruments, including real estate performance bonds, index-based weather insurance and climate derivatives, and social impact bonds. Third, analysis and classification of the likely types of water infrastructure where climate/green performance bonds could be applicable. Fourth, quantitative modelling within a stochastic framework would provide insights as to whether bond issuers and investors may see merit in using this new type of financial instrument to meet their objectives. And, finally, if the refined concept is proven theoretically and through modelling, participatory workshops with stakeholders could provide the basis for a pilot application.

Resilience of a multipurpose hydropower system to droughts

In Chapter 2, I showed how the resilience of a multipurpose hydropower system can be conceived as consisting of: robustness, resistance, and recovery time. Each of these components can be measured through hydro-economic modelling. However, the seasonal time step of the modelling framework used in Chapters 4 and 5 prevented a detailed resilience-based analysis in this thesis. Hence, future work could use a shorter time-step (e.g. weekly or monthly) to assess alternative water allocation regimes across these resilience metrics, particularly in terms of recurring droughts of different frequency and magnitude. Further, additional water-based services could be incorporated into the economic analysis where existing non-market valuation data is available, e.g. the economic benefits of recreational reservoir fisheries.

Enabling the provision of water services from pumped hydropower projects

The value of energy storage is increasing in many electricity networks as the penetration of variable solar and wind generation increases. Pumped hydropower projects provide the capacity to store excess electricity and rapidly dispatch electricity to meet rising loads or shortfalls in variable generation technologies. In deregulated electricity markets, hydropower companies can exploit arbitrage opportunities by pumping water to an upstream reservoir (when electricity prices are low) and generating electricity (when prices are high) by releasing water to a downstream reservoir. Pumped hydropower could also create opportunities for multipurpose operations and the increased provision of water services with no or reduced opportunity cost to hydropower companies. For example, downstream reservoirs can provide storage to replicate aspects of natural flow regimes or deliver water to irrigation. Fundamentally, the capacity for hydropower companies to generate revenues from recycling water raises the prospect of reduced trade-offs between the provision of energy and water services. Once again, however, regulation and incentives would be needed to realise this potential: pumped hydropower infrastructure, such as an additional dam and pumps, are costly. One option could be climate performance bonds that provide concessional finance for pumped hydropower projects that is conditional on the provision of additional water services. Another option could be a fixed water tariff that water users pay to the hydropower company to partially recover the costs of installing additional infrastructure. These and other options can be examined by adapting the hydro-economic modelling framework used in this thesis.

Participatory modelling for hydropower reforms

Desktop modelling needs to be connected to actual decision-making processes to influence reform agendas. An obvious extension of the current research would be the use of the hydro-economic modelling and participatory risk assessment frameworks to inform real-world hydropower regulation. For example, the United States Federal Energy Regulatory Commission's relicensing processes, the due diligence processes of multilateral banks and other lenders, or voluntary self-regulation processes, such as the Hydropower Sustainability Assessment Protocol. Further, these tools could be used in applied research to examine the potential for broader application of water pricing to multipurpose hydropower operations.

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